BEFORE THE
BOARD OF MINERALS AND ENVIRONMENT
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES

IN THE MATTER OF THE PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AIR QUALITY PERMIT APPLICATION OF HYPERION ENERGY CENTER - HYPERION REFINING LLC	)	PERMIT #28.0701-PSD
Draft Permit Issued: 9-08 Final Proposed Permit Issued: 12-08	)	

MOTION FOR PROTECTION OF CONFIDENTIAL INFORMATION

Hyperion Refining, LLC, ("Hyperion"), as permittee of its refinery and integrated gasification combined cycle facility, by and through its undersigned attorneys, respectfully requests the Board of Minerals and Environment ("Board") hear and grant this motion and find that certain information submitted to the Department of Environment and Natural Resources ("DENR") regarding Hyperion's Prevention of Significant Deterioration Air Quality Preconstruction Permit ("Permit #28.0701-PSD") issued August 20, 2009 be considered confidential. In support of this motion and pursuant to SDCL 34A-1-14, Hyperion states as follows:

1. On June 23, 2010 Hyperion properly and timely requested an extension of the "commence construction" deadline set out in Permit #28.0701-PSD.

2. In reviewing Hyperion's request for extension, DENR determined it would require more information and subsequently requested the submission of additional data from Hyperion, including information regarding cost and energy efficiency of combustion air preheaters which Hyperion maintains is confidential.

3. Hyperion submitted, as confidential, the requested information in two correspondences dated January 26 and February 2, 2011. (Copies of these correspondences are attached only to the Board's copy (as "A") of this motion and are submitted under veil of confidentiality.)

4. Energy efficiency data is highly protected in the refining and energy production industries. In fact, energy costs have come to represent as much as 82% of a refinery's operating expense. Proops, Kevin R. "EII Analysis Methodology: Gap Analysis vs World's Best EII." <u>2008 Fuels Refinery Performance Analysis</u>. 2010 HSB Solomon Associates LLC (Attached hereto as "B").

5. The requested information was submitted to DENR under a confidentiality designation and should remain confidential. This information is "sufficiently unique to affect adversely the competitive position of" Hyperion. In fact, such data is considered proprietary information throughout the industry. Friedman, David for National Petrochemical & Refiners Association. Letter to Environmental Protection Agency. 1 Dec. 2010. Re: PSD and Title V Permitting Guidance for Greenhouse Gases, 75 Fed. Reg. 70254 (November 17, 2010) (Attached hereto as "C").

6. In a report prepared for EPA in 2009 as preparation for GHG emission evaluations in the petroleum refining industry, it is noted "[m]uch of the data reported to EIA [Energy Information Administration within U.S. Department of Energy], particularly that reported by refiners, is classified by law as being proprietary. . . Most refiners are very careful not to reveal proprietary secrets that bear on economic performance." "For refiners the core of their business sensitive data consists of data on 'runs and yields' and economics." Office of Air and Radiation, U.S. Environmental Protection Agency. <u>Technical Support Document, Industry</u>

Overview and Current Reporting Requirements for Petroleum Refining and Petroleum Imports, Proposed Rule for Mandatory Reporting of Greenhouse Gases. 30 Jan. 2009. pp. 27-8 (Attached hereto as "D"). In this same study, the EPA acknowledges that a refiner's "more efficient equipment, better technical knowledge, and quicker business decision-making may result in substantially higher yields of higher value products, and hence, higher profits." *Id.* at 28. This is precisely the type of economic advantage information Hyperion is requesting be maintained as confidential at this time.

7. The information submitted as confidential directly relates to the process heater efficiency and process unit operating costs. Revealing this information to the public would deleteriously affect Hyperion's ability to maintain any cost advantage in the industry.

8. This information is not a part of any prosecution proceeding under Chapter 34A of South Dakota Codified Laws and therefore does not fall within the exception to SDCL 34A-1-14.

9. All air pollutant emissions data is disclosed in other materials that are publicly available regarding Permit #28.0701-PSD. Maintaining the confidential nature of the information as requested will not prevent evaluation of those emissions in relation to Permit #28.0701-PSD.

Hyperion requests the Board hear and grant this motion and consider the information submitted confidential in the remainder of the proceedings regarding Permit #28.0701-PSD.

Dated this 7 day of February, 2011.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing document has been served via E-mail and United States Mail, postage prepaid, on this 7 day of February 2011, to:

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Solomon Associates
M³ – Measure. Manage. Maximize.®

EII Analysis Methodology

Gap Analysis vs World's Best EII

2008 Fuels Refinery Performance Analysis

January 20, 2010

Kevin R. Proops
Senior Consultant

Introduction

The Energy Intensity Index (EII®)-related information and methodologies[1] outlined herein are proprietary and their expression in this document is copyrighted, with all rights reserved to Solomon. Copying or distributing EII-related material to anyone outside the companies that participated in HSB Solomon Associates LLC's (Solomon's) 2008 *Fuels Refinery Performance Analysis (Fuels Study)* or *Worldwide Paraffinic Lube Refinery Performance Analysis (Lube Study)* and its member companies without Solomon's written permission is prohibited.

Solomon introduced EII in its first *Fuels Study* of approximately 45 US refineries in 1980. Study participation and the resulting database have grown substantially since then. More than 350 refineries, which make up approximately 85% of worldwide capacity, were benchmarked in the 2008 *Fuels* and *Lube Studies*. Solomon's proprietary database includes detailed data on more than 500 refineries worldwide. Solomon's refinery efficiency methodologies are the standard within the refining industry.

In recent years, energy has come to represent 18–82% of a refinery's operating expense. As such, Solomon developed tools that allow *Fuels* and *Lube Study* participants to better focus their efforts toward making measurable improvements in energy efficiency.

One such tool is EII Analysis versus World's Best EII, which is supplied in the **EII Analysis** tab of the *_PA.xls* file. This analysis illustrates the main reasons underlying the EII performance gap between an individual refinery's EII and that of a "World's Best" EII peer group. This tool was introduced to *Fuels Study* participants during the 2008 *Fuels Study* results presentations and graphically presented as a waterfall diagram, refer to Figure 1. While this tool has been well received, many questions have been raised regarding the methodology employed in its development.

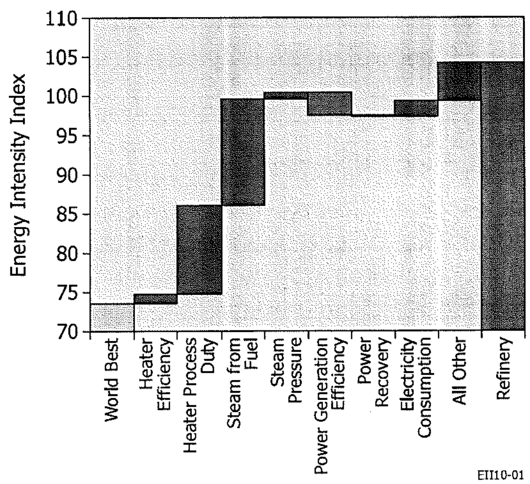

Figure 1. EII Gaps

This document describes the EII Analysis methodology in sufficient detail to enable each 2008 *Fuels Study* participant to self-calculate the main elements of the EII Gap. An updated version of the EII Gap is provided for each refinery in the attached *_EIIGap.xls* file. Solomon will continue to improve this product in the upcoming studies. All questions should be directed to Fuels@SolomonOnline.com.

[1] EII® is a registered trademark of Solomon. The absence of any indication as such does not constitute a waiver of any and all intellectual property rights that Solomon has established.

EII Analysis Methodology, Gap Analysis vs World's Best EII

Solomon defines "World's Best" as the weighted average data of six of the best individual refineries with excellent EII performance from the three *Fuels Study* regions:

- two from North and South America
- two from Europe, Africa, and the Middle East
- two from Asia/Pacific/Indian Ocean

Each of the World's Best EII refineries has an EDC greater than 1.5 million and a typical refining configuration. The composite 2008 World's Best EII is 73.5. The EII used in this analysis is the EII calculated and reported for each refinery participating in the 2008 *Fuels Study* using the 2008 *Fuels Study* validated input.

The following individual elements help explain the EII gap between the World's Best EII peer group and an individual refinery:

- Process Unit Fired-Heater Efficiency
- Process Unit Fired-Heater Process Duty
- Steam from Fuel Combustion
- Steam System Pressure
- Electric Power Generation Efficiency
- Power Recovery – Fluid Catalytic Cracker (FCC) Expander
- Electricity Consumption
- All Other

Process Unit Fired-Heater Efficiency

This element of the EII Analysis shows how the efficiency of the absorbed process duty in Process Unit Fired-Heaters impacts a refinery's EII. The EII delta between the efficiency of the Process Unit Fired-Heaters in the World's Best EII peer group and the efficiency of the Process Unit Fired-Heaters in an individual refinery is determined using *Equation 1*:

$$[(100 \div L51) - (100 \div J51)] \times J49 \times (J46 \div J45)$$

Equation 1

Where:

- J51[2] = Weighted-average Efficiency of Process Unit Fired-Heaters (Refinery Value), %
- L51 = Weighted-average Efficiency of Process Unit Fired-Heaters (World's Best Value), %
- J49 = Absorbed Process Unit Fired-Heater Process Duty (Refinery Value), % of Process Standard Energy
- J46 = Process Unit Standard Energy, energy units
- J45 = Total Standard Energy, energy units

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[2] These cell references tie directly to the included *_EIIGap.xls* workbook.

The Process Unit Fired-Heaters efficiency calculations used in the analysis are similar to those that are found at http://vganapathy.tripod.com/efficy.html. Solomon indicated in the 2008 *Fuels Study* input instructions that participants could report flue gas O_2 on a wet or dry basis and should comment if they reported on a dry basis. In the 2010 *Fuels Study*, Solomon will require that the flue gas O_2 be reported on a wet basis.

Note that the air preheater associated with a Process Unit Fired-Heater is within the boundary for this element of the EII Analysis. Furthermore, Process Unit Fired-Heater efficiency is the overall efficiency for the heater.

Process Unit Fired-Heater Process Duty

This element of the EII Analysis shows how process absorbed duty in Process Unit Fired-Heaters impacts refinery EII. The EII delta between the Process Unit Fired-Heater Process Duty in the World's Best EII peer group and the Process Unit Fired-Heater Process Duty in an individual refinery is determined using *Equation 2*:

$$(L49 - J49) \times (J46 \div J45) \times 100/L51$$

Equation 2

Where:

- J49 = Process Unit Fired-Heater Process Duty (Refinery Value), % of Process Standard Energy
- L49 = Process Unit Fired-Heater Process Duty (World's Best Value), % of Process Standard Energy
- J46 = Process Unit Standard Energy, energy units
- J45 = Total Standard Energy, energy units
- L51 = Weighted-average Efficiency of Process Unit Fired-Heaters (World's Best Value), %

Note that the Process Unit Fired-Heater Process Duty and the Process Unit Standard Energy exclude process units that can have intrinsic coke combustion (i.e., FCC, POX, Fluid Coker, Flexicoking™, Coke Calciner, etc.).

Steam from Fuel Combustion

This element of the EII Analysis shows how fuel combustion to generate steam impacts a refinery's EII. This area provides the largest EII improvement opportunity for the majority of *Fuels Study* participants, and is the key differentiator of first-quartile performance. The EII delta between the steam produced and purchased in the World's Best EII peer group and the steam produced and purchased in an individual refinery is determined using *Equation 3*:

$$L60 - J60$$

Equation 3

Where:

- J60 = Steam from Fuel Combustion (Refinery Value), % of Total Standard Energy
- L60 = Steam from Fuel Combustion (World's Best Value), % of Total Standard Energy

There are four sources of Steam from Fuel Combustion:

- Input Table 1 – Steam produced from boilers assessed at a world-wide *Fuels Study* average firing rate of 1,225 Btu/lb (2,847 kJ/kg)
- Input Table 1 – Steam produced from cogeneration at 1,100 Btu/lb (2,557 kJ/kg)
- Input Table 3 – Steam produced in process unit heaters calculated by summing the steam duty divided by heater efficiency of all process heaters that generate steam
- Input Table 16 – Net Purchased Steam

Energy reported for steam purchases and sales already include generation inefficiencies as required by Input Table 16 Instruction 11.

Steam produced from waste heat recovery equipment other than fired-heater convection sections is not included.

Steam System Pressure

This element of the EII Analysis shows how steam system pressure impacts a refinery's EII. The EII delta between the steam system pressure in the World's Best EII peer group and the steam system pressure in an individual refinery is determined using *Equation 4*:

$$54.3 \times \mathrm{LN}[(J62 + 14.7) \div (L62 + 14.7)] \times J60 \div 1{,}225$$

Equation 4

Where:

- 54.3 = Slope of Fit of Steam Enthalpy vs Pressure [Btu/lb = 54.3 LN (psia) – 68.3]
- Enthalpy in Refinery Steam vs World Best, Btu/lb = 54.3 LN (Refinery Pressure, psia) – 54.3 LN (World Best Pressure, psia) = LN (Refinery Pressure/World Best Pressure)
- LN = Natural Logarithm
- J62 = Steam System Pressure (Refinery Average Value), psig
- L62 = Steam System Pressure (World's Best Average Value), psig
- 14.7 = Addition to Bring Gauge Pressure to psi Absolute
- J60 = Steam Consumed, % of Total Standard Energy
- 1,225 = Btu/lb Steam (Enthalpy vs Pressure is Derived as Btu/lb Steam, 2,847 kJ/kg)

There may be some double-counting in this element of the EII Analysis, yet Solomon found that the contribution of the steam system pressure in explaining the EII Gap is minimal. Solomon will eliminate this element of the EII Analysis in the next *Fuels Study*, including it with the produced and purchased steam element.

Electric Power Generation Efficiency

This element of the EII Analysis shows how Electric Power Generation Efficiency impacts a refinery's EII. The reference values are the *weighted average* for each refinery, with purchases at 9,090 Btu/kWh. The EII delta between the average Electric Power Generation Efficiency in the World's Best EII peer group and the average Electric Power Generation Efficiency in an individual refinery is determined using *Equation 5*:

$$(L57 - J57) \div J57 \times J61$$

Equation 5

Where:

- J57 = Average Refinery Electricity Generation Efficiency (purchases at 9,090 Btu/kWh, 9.590 MJ/kWh)
- L57 = Average World's Best Electricity Generation Efficiency (purchases at 9,090 Btu/kWh, 9.590 MJ/kWh)
- J61 = Electricity Consumed (Refinery Value), % of Total Standard Energy

Power Recovery – FCC Expander

This element of the EII Analysis shows how power recovery from an FCC Expander impacts a refinery's EII. The first step is to determine the net power recovered as described by *Equation 6*:

$$\text{FCC Expander BHP} * 0.7475 * (9{,}090 - 4{,}000) * 24 * 366$$

Equation 6

Where:

- *FCC Expander BHP* = Input Table 1 FCC Power Recovery Train, brake horsepower
- 0.7475 = Conversion of Horsepower to kW
- 9,090 = Standard Heat Rate of Purchased Electricity (9,090 Btu/kWh, 9.590 MJ/kWh)
- 4,000 = Assumed Heat Rate of FCC Expander Power Generation (4,000 Btu/kWh, 4.22 MJ/kWh)
- 24 = Hours per Day
- 366 = Days per Year (2008 was a Leap Year)

The assumed 4,000 Btu/kWh (4.22 MJ/kWh) heat rate of FCC Expander Power Generation represents the minimum theoretical rate of 3,413 Btu/kWh (3.598 MJ/kWh) plus heat losses and motor-gear-generator inefficiencies.

The EII delta between the power recovery in the World's Best EII peer group and the power recovery in an individual refinery is determined using *Equation 7*:

J59-L59

Equation 7

Where:

- J59 = Refinery FCC Expander impact, % of Total Standard Energy
- L59 = World's Best FCC Expander impact, % of Total Standard Energy

If a study participant does not have an FCC Unit or an FCC Expander, this element of the analysis is still valid as it demonstrates the efficiencies achieved by the World's Best EII peer group.

Electricity Consumption

This element of the EII Analysis shows the effect that electricity consumption has on a refinery's EII. The reference values are the *weighted average* for each refinery, with purchases at 9,090 Btu/kWh (9.590 MJ/kWh). If a refinery generates at greater than 9,090 Btu/kWh and sells power, the generation inefficiency is charged to refinery consumed power (refinery sells at 9,090 Btu/kWh or lower, never higher). This energy netting methodology is standard throughout in the study. The EII delta between the electricity consumed in the World's Best EII peer group and the electricity consumed in an individual refinery is determined using *Equation 8*:

L61 – (J61 x L57 ÷ J57)

Equation 8

Where:

- J61 = Electricity Consumed (Refinery Value), % of Total Standard Energy
- L61 = Electricity Consumed (World's Best Value), % of Total Standard Energy
- J57 = Average Refinery Electricity Generation Efficiency (purchases at 9,090 Btu/kWh, 9.590 MJ/kWh)
- L57 = Average World's Best Electricity Generation Efficiency (purchases at 9,090 Btu/kWh, 9.590 MJ/kWh)

All Other

This element of the EII Analysis completes the EII waterfall diagram by closing the remaining gap. This EII delta, representing the unexplained portion of the EII waterfall diagram, is determined using *Equation 9*. It is explainable by improving the quality of the input in Input Tables 2, 3, and 16.

L20 – L8 – SUM(N11:N17)

Equation 9

Where:

- L8 = Refinery EII
- L20 = World's Best EII
- N11:N17= Sum of EII-Deltas Calculated using Equations 1-6 and 8

All Other may include impacts from coke combustion, SRU energy, TRU energy, hydrotreater compression energy, etc. that are not completely captured in the other elements of this EII Analysis. This All Other category should be small if the data reported is consistent with the input instructions.

If a refinery has a significant unexplained EII-delta of more than 5 EII numbers in this All Other category, then Solomon encourages the refinery to review the following checklist:

- Review the instructions in Input Table 3, including the Reference 3A and FAQ.
- Review the Refinery Fuel Gas Balance. Does Input Table 3 Fired Duty plus Input Table 2 Fired-Turbine Cogeneration Total Fuel to Unit equal Input Table 16 Fuels Consumed in the Fuels Refinery column (not including process coke, steam, and electricity)?
- Review the Steam Balance. Does Input Table 1 Steam Generation (Fired Boilers) capacities and utilizations correspond to Input Table 3 Boiler Steam Duty? Be aware that boilers making steam for electrical production with condensing turbines should be reported on Input Table 3 and not reported on Input Table 1. Is Steam Duty in fired-heaters (such as in the convection section) reported in Input Table 3 consistent with Input Table 16A Steam from Fired Process Heater Convection Section?
- Confirm that the Input Table 1 utilized boiler capacity is not overstated. Examples include: 1) steam allocated to an excluded facility but the total boiler capacity is reported, and 2) electric power generation boilers are included in steam generation in Input Table 1.
- Confirm that all data reported in Input Table 3 was reported on a process throughput or fuel-fired weighted average basis. The weighting should be based on fired duty or utilized capacity.
- Review the reporting of Hydrogen Plant steam production. Only report the net steam production for Hydrogen Plants in Input Table 3 (gross steam minus process steam). Net steam includes steam for CO_2 recovery solvent regeneration and to drive fan and pump turbines.
- Review the percent contribution of heater process duty to a typical process unit's EII standard energy. The fired-heater absorbed duty divided by unit standard energy should be at least 20–30% of the standard energy for most process units.
- Review all third-party energy transfers in and/or out of the Fuels Refinery Boundary reported incorrectly.
- Review the reporting of convection air preheat systems as Other Duty in Input Table 3.
- Confirm the inclusion as Other Duty in Input Table 3 items such as CO boilers, calciners, and shaft work for gas turbines or any other external source of duty entering/leaving the Fuels Refinery Boundary (i.e., hot oil). See the attached FAQ.
- Review accuracy of electrical production efficiency reported on Input Table 16 for electric power generation and for cogeneration.
- Was a gas turbine that is not integrated into a cogeneration unit reported?

“C”

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December 1, 2010

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Attention Docket ID No. EPA-HQ-OAR-2010-0841

Subject: PSD and Title V Permitting Guidance for Greenhouse Gases, 75 Fed. Reg. 70254 (November 17, 2010).

Dear Sir/Madam:

The National Petrochemical & Refiners Association ("NPRA") is pleased to provide comments concerning the proposed guidance titled "PSD and Title V Permitting Guidance for Greenhouse Gases" referenced above.

NPRA comprises more than 450 member companies, including virtually all U.S. refiners and petrochemical manufacturers. Our members supply consumers with a wide variety of products and services that are used daily in homes and businesses. These products include gasoline, diesel fuel, home heating oil, jet fuel, asphalt products, and the chemicals that serve as "building blocks" in making plastics, clothing, medicine and computers.

Like many industrial sectors, NPRA's members emit greenhouse gases ("GHG") as a result of their manufacturing activities. NPRA members, however, have also made large investments in efforts to improve air quality in the United States. The refining industry alone has spent nearly $50 billion to remove sulfur from gasoline and diesel fuel and in providing reformulated gasoline. NPRA refining and petrochemical members have also invested heavily in controlling emissions from their facilities. These efforts have contributed to substantial local and national air quality benefits. Overall, total emissions of the six principal air pollutants in the United States have been reduced by 54 percent since 1980.

NPRA

These comments provide some of the initial industry thought on Best Available Control Technology ("BACT") and how it should be applied to GHG standards. How BACT is defined and implemented has significant implications for the refining and petrochemical industries as well as all of the other entities that will have their GHG emissions regulated by the states for the first time under the Clean Air Act. Given that many of our companies operate in several states, we have concerns that this BACT guidance will be applied inconsistently among the states. Our comments will address some of these concerns including legal issues (that the guidance does not conform to Clean Air Act Permitting requirements), performance benchmarking, averaging periods, the application of energy efficiency and the availability of carbon capture and sequestration. In addition, we have also provided a critique of some of the relevant BACT examples that are included in the Appendices.

We also have a major concern with the incredibly brief timeframe under which these comments have been drafted. While this is not a formal rulemaking, a 14-day comment period (over a major holiday) on such an important matter is simply unacceptable. Furthermore, the Agency suggested in publication of the document that comments should focus mainly on technical and calculation errors. EPA also stated in the publication that "this guidance is hereby in effect and consequently, EPA and other agencies may apply this guidance without, and regardless of, any additional action by EPA specific to this guidance." These statements do not seem consistent with a commitment to listen and respond to comments from stakeholders and the public.

The lengthy debates on GHG BACT through the Clean Air Act Advisory Committee for almost a year signaled that the issue was one that would require significant debate and discussion. These debates ultimately delayed the release of the guidance until late 2010 and forced a severely truncated comment period in order for the guidance to be available for state regulators by January 2, 2011. However, the controversy in defining BACT guidance for GHG reduction throughout the past year should have necessitated a far more significant and robust review by a broader group of stakeholders. This is simply too important to not get right, as vague or simply inaccurate guidance may have serious detrimental repercussions over the long term.

GHGs have never before been regulated and this BACT guidance requires a far more extensive review process by state regulators, the regulated community and the EPA. The BACT process has generated a tremendous amount of interest among all affected parties, and the implementation of BACT under the Prevention of Significant Deterioration ("PSD") and Title V processes will result in significant costs for all regulated entities. NPRA will also comment at a later date on the refinery sector paper that was published along with the BACT guidance. However, the compressed 14-day comment period simply will not allow for meaningful comment on the paper at this time.

Legal Issues Related to the BACT Guidance

1. The GHG Guidance Does Not Conform to Clean Air Act Permitting Requirements.

EPA's PSD and Title V Permitting Guidance for GHGs addresses issues arising from the Agency's determination that GHGs are "subject to regulation" under the Clean Air Act ("CAA"). Specifically, the GHG Guidance seeks to apply traditional "top down" analysis of BACT options in CAA permitting actions for new and modified sources. This process is generally defined in, and has been applied through other agency guidance, in particular the 1990 Workshop Manual.

"Step 1" of the BACT process is to identify all available control technologies for BACT for a new source or a source undergoing a modification which triggers permitting requirements. Thus, Step 1 essentially "fences the yard" of options that may be considered to be available for a source – options which may later be reviewed by a permitting agency and either required of the source or rejected. In describing its approach to Step 1, GHG Guidance states that "EPA has long recognized that a Step 1 list of options *need not necessarily include* inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant." (Emphasis added.) We would submit that consideration of such options is not only not "necessary," but that consideration of options that would fundamentally redefine a source is contrary to both the CAA and existing regulations.

The CAA clearly bases the review of a PSD permit on the application that is submitted by the entity seeking the permit, i.e., the facility which is proposed to be constructed or modified. CAA section 165(a)(1) bars construction of facilities until permits have been issued for "*such proposed* facility in accordance with this part . . ." (Emphasis added). CAA section 165(a)(2) provides that analysis of preconstruction permits are to be based on the "proposed permit." CAA section 165(a)(2) also makes it clear that required analysis is particularized as to the facility proposed (e.g., by providing that EPA is to assess the air quality impact of "such source"). CAA section 165(a)(3) further refers to "such facility" and requires that "emissions from the construction of operation of *such facility* will not cause, or contribute to, air pollution in excess of . . .[maximum allowable increases, national ambient standards and other applicable emission standards]." (Emphasis added).

Thus it is clear that Congress took particular care in defining the facility which is required to be subject to EPA review before construction is allowed to commence – it is unquestionably the proposed facility, the facility that the permit applicant wants to build or modify. Current EPA regulations confirm that assessing the impact of a source during the PSD permit process is with reference to the "proposed source."[1] EPA lacks statutory authority to impose different requirements through the issuance of guidance documents such as the GHG Guidance or to change existing regulations except through public notice and comment requirements contained in the CAA.

Despite these clear indications in law and regulation, the GHG Guidance sanctions a process by which state permitting agencies will place themselves in the position of second-guessing the "goal, objectives, purpose or basic design of the proposed facility in its application."[2] By suggesting that permitting agencies take a "hard look" at the applicant's proposed design, EPA is essentially advocating that state agencies and state permitting personnel (who may or may not have relevant technical or business experience in the type of facility that is being proposed to be built or modified) review an applicant's "basic design" as well as the facility's "fundamental business purpose." While EPA indicates that permitting authorities should accomplish this task without disrupting the

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[1] *See* 40 CFR 51.166(k).

[2] GHG Guidance at 27.

"applicants basic business purpose for the proposed facility,"[3] the type of analysis that EPA recommends attempts to place permitting authorities clearly in the shoes of the private businesses and question whether they are selecting the best engineering solutions, the best production processes and best maximization of their capital investment. The CAA and its current implementing regulations do not require such a result.

While EPA cites certain decisions of the Environmental Appeals Board ("EAB") for the interpretation of the CAA it advances in the GHG Guidance, it seeks to minimize other decisions. For example, EPA paraphrases part of the EAB's decision in *In re Knauf Fiber Glass,*[4] yet cites other EAB decisions in a more limited manner. In contrast to EPA's emphasis on the "hard look," the EAB in its decision in *In re Praire State Generating Company*[5] decided and held that there was no error when a permitting authority did not require analysis of low-sulfur coal alternatives for a proposed facility. In this decision, the EAB addressed several matters concerning the limits of permit review allowed under the CAA and specifically addressed statutory arguments raised by EPA's Office of Air and Radiation stating that:

> Looking in the first instance to how the permit applicant defines the proposed facility's purpose or basic design in its application not only harmonizes the BACT definition with the permit application process in which the definition must be applied, but also is consistent with the Agency's long-standing policy against redefining the proposed facility. When the Administrator first developed this policy in *Pennsauken*, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source *as the applicant has defined it*" and that "the source itself is not a condition of the permit." *In re Pennsauken County, N.J., Res. Recovery Facility,* 2 E.A.D. 667, 673 (Adm'r 1988) (emphasis added); *see also In re Old Dominion Elec. Coop.,* 3 E.A.D. 779, 793 n.38 (Adm'r 1992) ("Traditionally, EPA has not required a PSD applicant to change the fundamental scope of its project."); *In re Spokane Reg'l Waste-to-Energy,* 2 E.A.D. 809, 811 n.7 (Adm'r 1989) (same).[6]

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[3] Id. at 28.

[4] Id. at 27-28.

[5] PSD Appeal No. 05-05 (EAB Aug 24, 2006).

[6] Id. at 29.

Citing *In re Knauf Fiber Glass,* EPA states in the GHG Guidance that it "does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire."[7] The Agency then goes further and attempts to minimize the entire issue by stating that redefinition of the source is "ultimately a question of degree that is within the discretion of the permitting authority."[8] EPA then attempts to further empower permitting authorities by indicating that they should affirmatively determine "the applicant's basic or fundamental business purpose or objective."[9]

As noted above, such a position is contrary to the CAA and statutory provisions providing for the PSD permiting process. But in addition, this view ignores the Agency's own precedent. As cited above in *Prairie State*, the concept of redefining the source has not been a mere EPA and state dalliance, but instead represented the Agency's "long standing policy." Rather than implement "the time tested process that they have used for other pollutants,"[10] EPA is attempting within the GHG Guidance to reverse course and advise permitting agencies to consider any and all options for the construction of a source based solely on the discretion of the permitting agency. At bottom, this is effectively indicating that the PSD program is without statutory structure. If matters of allowing the construction of one type of source or another is solely a matter of discretion within the power of a permitting agency, the EPA effectively robs CAA section 165 of any force or meaning.

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[7] GHG Guidance at 28.

[8] Id.

[9] Id.

[10] "EPA Issues Pollution Permitting Guidance for States/Focus is on improving energy efficiency to reduct GHG pollution from the largest industrial facilities," EPA Press Release, November 10, 2010.

2. EPA Correctly Interprets Regulations Regarding Issuance of a Permit

The GHG Guidance provides that construction permits issued prior to the date on which EPA interprets PSD permitting requirements for GHGs to apply[11], do not need to address GHG emissions. NPRA believes this interpretation is compelled by statute, but further agrees with EPA's assessment that this interpretation is consistent with current implementing regulations.

CAA section 165(a) provides that construction may not be commenced on a "major emitting facility" to which the provisions of the section apply until a permit has been "issued."[12] Thus, the CAA clearly indicates that permit issuance is the defining event in meeting requirements imposed by the PSD program. Requirements that arise subsequent to permit issuance cannot be required of a source through the authority of CAA section 165. Indeed, to attempt to do so would be contrary not only to the plain statutory terms of the CAA, but to judicial precedent prohibiting retroactive requirements.[13]

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[11] EPA currently considers that GHGs are "subject to regulation" under the CAA as of January 2, 2011 for purposes of applying PSD program requirements based on the Agency's interpretation that an air pollutant is "subject to regulation" when regulatory requirements "take effect." EPA adopted this interpretation within its Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting Programs, 75 Fed. Reg. 17004 (April 2, 2010). In that reconsideration, EPA determined that GHG standards for light duty automobiles would "take effect" no earlier than January 2, 2010 when Model Year 2012 vehicles could be subject to certification. Id. at 17,007. In agreeing with EPA's interpretation regarding permit "issuance," NPRA does not adopt or indicate its agreement with EPA's interpretation regarding when GHGs are "subject to regulation" under the CAA or its specific interpretation as to when motor vehicle regulations controlling certain GHGs can be considered to "take effect".

[12] CAA section 165(a)(1).

[13] *See*, for example, *Landgraf v. USI Film Products*, 611 U.S. 244, 269-70 (1994) where in assessing whether a law is retroactive the Supreme Court applied the test of "whether the new provision attaches new legal consequences to events completed before its enactment.". Also, in *National Mining Association v. Department of Labor*, 292 F.3d 849 (D.C.Cir 2002), in assessing whether regulatory actions were impermissibly retroactive, the U.S. Court of Appeals for the District of Columbia Circuit examined whether a requirement "creates a new

EPA correctly interprets existing regulations to prevent alternative views of this matter. As cited by the Agency, 40 CFR Part 124 defines a permit as "issued" when the Regional Office makes a final decision with respect to the permit application. Thus, PSD permits issued before January 2, 2011, clearly cannot be required by EPA or state permitting agencies implementing the PSD program to address GHG emissions.

Averaging Periods

1. EPA Guidance on Averaging Periods Should be No Shorter than a 12-Month Rolling Average

NPRA supports EPA's acknowledgement that the environmental concerns with GHGs are with their cumulative impact on the environment, and thus monitoring metrics should focus on longer-term averages (pg 47). However, the examples and recommendations provided in the GHG BACT guidance document indicate a preference for short-term averages. For example:

> The permitting authority is also responsible for defining the form of the BACT limits, and making them enforceable as a practical matter. In determining the form of the limit, the permitting authority should consider issues such as averaging times and units of measurement. For example, a final permit may include a limit based on pounds of emissions on a 24-hour rolling average or a limit representing a percentage of pollutant per weight allowed in the fuel. (pg 46)
>
> Furthermore, since the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages (*e.g.,* 30- or 365-day rolling average) rather than short-term averages (*e.g.,* 3- or 24-hr rolling average). (pg 47)

obligation, or imposes a new duty, or attaches a new disability in respect to transactions or considerations already passed." Id. at 859.

Emission limit expressed in lbs of CO_2e emissions per pound of steam produced, averaged over 30 day rolling periods; (pg F-3, BACT example for Natural Gas Boiler)

Emission limit in pounds of CO2e emitted per pound of hydrogen produced, averaged over rolling 30-day periods; (pg H-3, BACT example for Hydrogen plants)

The repeated references to 30-day periods notwithstanding, NPRA contends that any averaging period shorter than 1 year constitutes a "short-term average" which is completely unnecessary in the context of GHGs and creates a range of problems, including:

- **Criteria Pollutant Paradigm:** Short-term emissions limits may be necessary for all criteria pollutants as they have been shown to have environmental impacts in, and consequently National Ambient Air Quality Standards (NAAQS) for, limited periods such as hours or days. All GHGs that will be subject to regulation under the Tailoring Rule are recognized by EPA as global pollutants, with atmospheric life-spans measured in years, and consequently are distributed world-wide. Their environmental impacts are based solely on their cumulative effect in the atmosphere. NAAQS pollutants, by contrast, have chemical and physiological effects that can be measured over much shorter time periods. While criteria pollutants by their nature must be monitored on short time scales, the same cannot be said for GHGs as there are no short-term effects associated with GHG emissions. The paradigm of controlling and monitoring criteria pollutants cannot be applied to a fundamentally different substance, such as GHGs. Consequently, we see no scientifically justified reason for short-term averaging periods in determining GHG BACT.
- **Variations in fuel composition**: Short-term averaging periods can introduce issues where fuel composition is variable. For instance, refinery fuel gas can have variable methane content. Due to combustion inefficiencies inherent in all industrial combustion equipment, an increase in methane composition will increase methane emissions and consequently the CO_2e emissions. While these fuel variations can typically be compensated for over the course of a year, short-term GHG averaging periods will create difficulties in ensuring compliance and would require specific procedures to control methane composition (which are generally not current practice and would require significant capital expenditures), or cutting production by limiting firing rates.
- **Impacts on Monitoring**: Title V permitting typically requires monitoring sufficient to confirm compliance with applicable emission limits. Placing short-term GHG

emission limits on equipment will necessitate procedures and/or monitoring equipment commensurate with these limits. We find this an unnecessary burden and expense for a frequency any greater than a 1-year period. Data quality would not suffer from annual compliance limits, while instead minimizing the burden and expense on regulated facilities in monitoring equipment and more frequent calculation methodologies.

- **The Recommended 30 Day Period is Non-Standard**: The 30 day averaging period mentioned throughout the BACT guidance does not fall evenly into a 365-day year, and would create temporal difficulties in maintaining an averaging period that does not conform with time as measured over the course of the calendar year. Compliance periods would soon straddle months and would not coincide with any other averaging period, creating confusion and difficulties in demonstrating compliance.

NPRA recommends that EPA revise this guidance to be consistent with the original premise that short-term limits are unnecessary and limit examples and recommendations to a 1-year averaging period (or equivalently, 12-month rolling averages).

Energy Efficiency

In the BACT guidance document, EPA places a great deal of emphasis on energy efficiency as a means of achieving lower GHG emissions. EPA states on page 30 of the draft guidance, "Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews." In addition, the Agency further states on page 30 that "EPA encourages permitting authorities to use the discretion available under the PSD program to include the most energy efficient options in BACT analyses for both GHG and non-GHG regulated New Source Review pollutants. While energy efficiency can reduce emissions of all combustion-related emissions, it is a particularly important consideration for GHGs since the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-derived pollutants."

NPRA members certainly understand the value of energy efficiency, and refineries have been employing all varieties of energy-efficient projects over the past 40 years. Energy costs can consume up to half of a refinery's operating costs and up to 30-40 percent of a petrochemical facility's operating costs. But given its importance to the BACT discussion, how will energy efficiency be determined? Will it be across a specific piece of equipment, across the production unit, or across the entire facility? Industry believes that energy efficiency should be applied to the operation of the specific piece of equipment.

Because energy efficiency is still so vague and loosely defined, we need to point out some of the issues that we have encountered as we have attempted to employ energy efficient projects. New equipment is built and installed with a wide range of possibilities. However, older equipment has more limited opportunity for changes to maximize energy efficiency. For example, once a boiler is designed, constructed and installed, it can be difficult and costly to improve its efficiency above the original design. In addition, there are often trade-offs between energy efficiency and emissions and plant reliability. Energy efficiency in combustion sources can differ drastically by the different fuel type used. If fuel type varies due to economic conditions or fuel availability, energy efficiency will also vary. For example, gas and oil have lower boiler efficiencies than coal because these fuels have progressively higher hydrogen contents which generate water during combustion.

The BACT Guidance is too vague on energy efficiency for permitting authorities and sources undergoing BACT review. The Guidance suggests that permitting authorities may consider not only technologies or processes to improve efficiencies of emitting units, but also an entire facility's energy utilization (page 31). This is beyond the bounds of what is appropriate in a BACT review and it is too vague in providing permitting authorities any sense of where their evaluations should be focused. The refinery sector paper, upon which we will comment at a later date, lists 40 different energy efficiency options for refineries. How many options should the regulator require the refinery to implement? Should all forty be employed or just five or six? The energy efficiency guidance does not provide an appropriate answer to that question and leaves a great deal of uncertainty to the regulated facility that is undergoing BACT analysis.

Petrochemical and refining companies have already invested hundreds of millions of dollars on energy efficiency improvements without any government incentive or mandate because it makes good business sense to do so. Those activities should be recognized by the EPA as BACT that are already in place.

EPA should continue to focus on combined heat and power (CHP) and make it very attractive for facilities and utilities to install CHP at large steam users. NPRA members are already employing CHP at a number of their refineries and petrochemical facilities. EPA should be assisting in removing regulatory hurdles to make these investments, as these CHP units often operate at 50 to 70 percent higher efficiency rates than single-generation facilities.

Performance Benchmarking

1. EPA's Perspective on Benchmarking

EPA has provided its perspective on the importance of benchmarking as follows:

> An available tool that is particularly useful when assessing energy efficiency opportunities and options is performance benchmarking. Performance benchmarking information, to the extent it is specific and relevant to the source in question, may provide useful information regarding energy efficient technologies and processes for consideration in the BACT assessment. Comparison of the unit's or source's energy performance with a benchmark may highlight the need to assess additional energy efficiency possibilities. To the extent that benchmarking an emissions unit or source shows it to be a poor-to-average performer, the permitting authority may need to document and evaluate whether greater efficiencies are achievable. To ensure that the source is constructed and operated in a manner consistent with achieving the energy efficiency goals determined to be BACT, consideration should be given to the individual and overall impact of the various measures under consideration. For example, in the case of numerous small energy saving measures, the intended effect of such measures could be reflected in projecting the GHG emissions limit or output-based standard for the emissions unit. On the other hand, it may be appropriate to include specific energy efficiency measures or techniques in the permit (as well as reflected in the GHG emissions

> limit) where such measures could clearly have a noticeable effect on energy savings.[14]

EPA has further stated:

> There are a number of resources available for benchmarking facilities. For example, EPA's ENERGY STAR program for industrial sources offers several resources that can assist with performance benchmarking. To evaluate the energy performance of an entire facility,[15] ENERGY STAR developed sector-specific benchmarking tools called plant Energy Performance Indicators (EPIs).[16] For sectors where an EPI has been developed, these tools may be used to assess a plant's performance compared to the industry. At a unit and process level, ENERGY STAR has developed sector-specific Energy Guides for a number of industries. These Energy Guides discuss in detail processes and technologies that a permit applicant or permitting authority may wish to consider. This type of information may be particularly useful at the initial stages of the GHG BACT permitting process as the RACT/BACT/LAER clearinghouse (RBLC) is populated and

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[14] Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance For Greenhouse Gases, US EPA, Research Triangle Park, NC, November 2010.

[15] For PSD applicability, the scope of the "major stationary source" is determined by the definition in 40 CFR 52.21(b)(1), and the title V "major source" is defined in 40 CFR 70.2. The PSD and title V regulations distinguish between a "facility" and a "stationary source"; in fact, the regulations include a facility as type of stationary source. 40 CFR 52.21(b)(5)-(6), 40 CFR 71.2. However, in this guidance, source and facility are used interchangeably to

generally designate pollutant emitting structures and do not designate official positions regarding applicability

unless otherwise noted.

[16] Current ENERGY STAR industrial sector EPIs can be found at http://www.energystar.gov/EPIS.

updated with case-specific information.[17] Additional resources can be found in Appendix J of this document.

2. NPRA's Members Use a Different Approach to Benchmarking

Many of NPRA's member companies conduct on-going benchmarking studies on a wide variety of topics, including energy use. However, none of the industry benchmarking is used to specifically select particular technologies or equipment. The benchmarking data is used to learn what others are accomplishing and for broad performance monitoring. Based on the benchmarking data, opportunities for improvement are identified and evaluated for applicability within the constraints of the company and individual plants.

Benchmarking data cannot be used to make specific technology or equipment selections due to the high variability of feedstocks, products and operations within the industry. As the Lawrence Berkley Laboratory found: "Every refinery and plant will be different. The most favorable selection of energy efficiency opportunities should be made on a plant specific basis."[18] Given the unique nature of every plant, it is inappropriate for EPA to mandate technology selections based on benchmarking data.

3. Performance Benchmarking Can Be a Useful Tool, But It Has Limitations in the Refining and Petrochemical Sectors

EPA has identified performance benchmarking as a "particularly useful" tool for assessing energy efficiency opportunities. NPRA agrees with this assessment in principle, and a number of our members have participated voluntarily in EPA-sponsored benchmarking programs such as ENERGY STAR

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[17] The RBLC provides access to information and decisions about pollution control measures required by air pollution emission permits issued by state and local permitting agencies so that the information is accessible to all permitting authorities working on similar projects. The expanded RBLC includes GHG control and test data, and a GHG message board for permitting authorities.

[18] Ernst Worrell and Christina Galitsky, Energy Efficiency Improvement and Cost Saving Opportunities For Petroleum Refineries, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California, February 2005.

and Natural Gas STAR. However, in the context of the PSD program, performance benchmarking is not the appropriate means to select BACT for GHGs. The PSD program focuses on controlling emissions from specific equipment or emitting units and, therefore, system-wide energy efficiency benchmarking approaches are not appropriate. The specific challenges of process benchmarking in the petrochemical and refining industry include:

- The unique nature of the industries' raw materials, e.g., crude oils, intermediate products, natural gas and natural gas liquids.
- The unique nature and mix of the industries' products, e.g., consumer products, intermediate products and liquefied petroleum gas (LPG).
- Lack of consistent publically available benchmarking data.
- The need to retrofit new process units into existing plants with numerous utility, space and other site-specific constraints.

The following describes each of these specific industry factors and how they present challenges to benchmarking.

A. The Unique Nature of the Industries' Raw Materials (e.g., crude oils, intermediate products, natural gas and natural gas liquids)

The refining and petrochemical industries rely on an almost infinite variety of feedstocks. Each producing crude oil field is unique and within the individual field, crude oil quality varies by individual well. Further, the characteristics of the oil vary over time and field management techniques. The particular variables affecting crude oil quality are also numerous, e.g., gravity, sulfur, nitrogen and metals content, distillation characteristics, paraffinic, aromatic and olefin contents, viscosity, and acid index, to name the major qualities affecting operations including energy requirements. Other petrochemical and refining industry feedstocks also are highly variable in quality, including intermediate products, natural gas and natural gas liquids. Natural gas quality is also highly variable for many refineries, and petrochemical plants do not use "pipeline quality" natural gas. Many of the companies are integrated and have direct access to natural gas via proprietary pipelines. Due to the proprietary nature of these systems, the gas may have different qualities than gas purchased for a regulated pipeline.

Each feedstock requires different energy inputs to be converted to products acceptable to consumers. For example, the example of BACT for a hydrogen plant in a petroleum refinery in Appendix H[19] would not be applicable if the feedstock stream to the hydrogen reformer was different than the other benchmarked units. A lower BTU gas, typical of some proprietary natural gas systems, would require more feedstock heating and additional product purification affecting the energy consumption per unit of output. This variability in feedstocks to the refining and petrochemical industries makes benchmarking comparisons non-applicable for technology or equipment selection.

B. The Unique Nature and Mix of the Industries' Products, e.g., Consumer Products, Intermediate Products and LPG

As noted above, each refinery and petrochemical plant uses a unique mix of feedstocks that affect energy consumption. Further, each plant makes a unique mix of products based on local demand, processing capability and raw material mix and availability. Different products have different energy requirements, e.g., a refinery that just produces heavy fuel oil, low-octane gasoline and high-sulfur diesel fuel have a much lower energy consumption than a modern facility that produces a variety of gasoline grades, ultra-low sulfur diesel and aviation fuel.
This variability in product mix makes benchmarking comparisons non-applicable for technology or equipment selection.

C. Lack of Consistent Publically Available Benchmarking Data

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[19] Op. Cit., No. 14.

The Energy Star program and its Energy Performance Indicators[20] are not available for the refining and petrochemical industries. All benchmarking data in the industry is proprietary information collected under strict confidentiality provisions. EPA cites the European benchmarking efforts.[21] Note that the system selected was deemed far from perfect by all participants and more importantly addressed whole plants, not individual process units.
The lack of consistent publicly available benchmarking data makes benchmarking inappropriate for technology or equipment selection purposes in the refining and petrochemical industries.

D. The Need to Retrofit New Process Units into Existing Plants with Numerous Utility, Space and Other Site-Specific Constraints

The refining and petrochemical industries are classified as mature in the U.S. No new "grassroots" plants are being built. All projects take place within existing plants. This means that new process units are constructed under a number of constraints that would not exist at a "grassroots" plant. Among those constraints are the effect of other downstream and upstream process units, utility lines and space. Each of these can impact the energy intensity of the new unit. As an example, EPA cites the use of an air preheater[22] as a means to reduce energy consumption for a boiler. While that is true, air preheaters consume a bigger plant footprint, making it an infeasible option in many existing plants. Due to the pre-existing constraints at all plants, benchmarking is not appropriate for technology or equipment selection purposes in the refining and petrochemical industries.

The examples provided illustrate the difficulty and complexity in appropriately applying energy efficiency benchmarking in this regulatory context. It becomes clear that it is not appropriate for EPA to apply facility-wide energy efficiency performance benchmarking in the context of the PSD program.

Carbon Storage and Sequestration

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[20] Op. Cit., No. 18

[21] Op. Cit., No. 14

[22] Op. Cit., No. 14.

1. Carbon Capture and Storage Is Not Yet an "Available" Technology

Carbon Capture and Storage (CCS) is a grouping of technologies designed to capture carbon dioxide emitted from power generation and transport it to geological formations where it may be permanently stored. Large-scale deployment of CCS is currently impossible for at least two reasons: 1) the prohibitively high cost of capturing, transporting, and storing carbon dioxide emission, and 2) the lack of a legal and regulatory infrastructure (including liability protection) to guide this process, particularly ensuring the permanence of storage, which presents significant technical and theoretical difficulties. A number of companies including some NPRA members are working hard to perform the necessary research and pilot projects to overcome these and other obstacles, but significant work still remains to be completed.

Given this current situation, it is perplexing that EPA simply proclaims CCS "available for large CO2-emitting facilities," *id.* at 33, and insists on, in numerous instances, "comprehensive" consideration of this entirely experimental option. *Id.* at 37. Carbon Capture and Storage is in no sense "available" as of yet. It has been attempted on a small scale in pilot projects receiving subsidies from the government along with special regulatory treatment, but these early efforts, of course, cannot demonstrate that indefinite storage, the entire point of CCS, is available or even *possible* in the long term.

Additionally, the Advanced Notice of Proposed Rulemaking (ANPR) for GHG emissions that EPA released in July 2008 includes a considerable discussion on CCS that the Agency has simply ignored in the BACT guidance. For example, the following passage in the GHG ANPR (75 FR 44370) states that CCS won't be commercially available even to new power plants until 2025 based upon DOE studies and goals:.

The DOE carbon sequestration program goal is to develop at R&D scale by 2012,

fossil fuel conversion systems that offer 90 percent CO2 capture with 99 percent storage

permanence at less than a 10 percent increase in the cost of energy services from new

> plants. For retrofits of existing facilities, the task will be much harder, and the penalties in terms of increased cost of power production from those plants likely will be much higher. We expect that these integrated systems for new plants will be available for full commercial deployment – that is, will have completed the demonstration and early deployment phase – in the 2025 timeframe.

For EPA to now suggest CCS as BACT in view of the ANPR is completely contrary to this discussion. EPA needs to provide additional updates to the public if there have been new CCS developments since this information was published in 2008.

Furthermore, the suggestion in the Guidance that enhanced oil recovery in any way alters this conclusion that CCS is now available is entirely unfounded. *Id.* at 43. Enhanced oil recovery is not a method of emission control—it does not guarantee that the carbon dioxide will be *stored*, which is the most difficult hurdle for CCS technology. Rather, enhanced oil recovery is an end-use of carbon dioxide. Simply put, enhanced oil recovery is not a control option, and EPA's presumption that it reduces the cost of CCS is not based upon commercial experience as it cannot be relied upon as a long term option. NPRA supports the government's ongoing efforts to try to make CCS technology widely available through research and development, but for now, the Guidance should make clear that it is not "available" under Step 1 of the top down process and that CCS is not a viable BACT option.

<u>Comments Related to Specific EPA BACT Examples</u>

1. **Appendix F – BACT Example- Natural Gas Boiler**

In the BACT example for a natural gas boiler, five possible technologies were identified in Step 1. Two more technologies were identified in the public comment period. Almost all of the technologies made it through to Step 5 of the BACT process and, therefore, had to be implemented by the applicant. This example leaves the impression that if 15 technologies had been identified in Step 1, potentially 13 would have made it through to BACT Step 5. What is unclear at this point for a PSD or Title V applicant is the number of controls that will be required.

Additionally, for boilers and heaters, there are an almost unlimited number of modifications (vendors, equipment, software, sensors, etc.) available and marketed to improve efficiencies. The list is extensive and many of these technologies overlap with the others; they are not mutually exclusive. The example in Appendix F seems to imply that a facility must install every technology that is feasible, has a reasonable payout, and will add to the overall efficiency. This could lead to an almost limitless list of modifications that could be made.

The approach to require the review of all possible control options is an extremely high burden. NPRA is not sure that any comprehensive list of possible controls even exists or is updated. Vendors approach members every day with a new "miracle device" that guarantees energy savings, but these claims are difficult to evaluate. This makes it very difficult to decide which control options should be included in the BACT analysis.

The example in Appendix F does not specifically require analysis all of combinations, since it assumes all 5 examples are independent and can be done. But what if there are 20 options or more, many of which interact with each other? This may require testing subsets of certain combinations of controls, and comparison of the "combination sets" for effectiveness. That is a very high burden and will often be untested in practice.

The example does not include any compliance margin or operating window. Most boilers/heaters will have one level of efficiency when operating at full throttle and much different efficiencies when operating at lower turn-down levels. This variation in efficiency is not discussed in the example, nor is seasonal variation discussed, and it is unclear if any provision is made for turn-down situations.

Appendix F does not explicitly state that the user builds its list of BACT options by consulting the RACT/BACT/LAER clearinghouse. We think the initial search for control options needs to be described more explicitly in this example. In addition, physical plot space is often limited at facilities and should have been considered in the Appendix F example. If a certain control requires addition of equipment of a significant size, we would suggest that the example be tailored to show that the control might be thrown out as infeasible.

2. Appendix H- BACT Example-Petroleum Refinery Hydrogen Plant

CCS should have been eliminated in Step 1, as building a 500-mile pipeline (or even a 20 mile pipeline) is infeasible for any company not involved with the pipeline industry. There are eminent domain issues, and right-of-way issues that cannot be appropriately evaluated in the normal project evaluations for BACT. CCS has not been commercially proven in the U.S., and should not have been carried to Step 4.

CCS should be automatically eliminated from consideration until further commercial development and legal liability issues are handled. The liability associated with the long-term (100,000 years+) storage of CO_2 is not a liability any American company is willing to undertake. The liability associated with the underground storage of CO_2 is huge, unproven, and uninsurable. The BACT analysis example should not imply that each applicant should analyze this issue.

BACT should not include offsite facility construction. Building a pipeline is extremely expensive and complicated. Designing and building offsite facilities like pipelines is far beyond the skills of all but the very largest of American industrial facilities. Designing and building a pipeline requires years of planning, acquisition of right-of-ways, etc. Some additional concerns include:

- While a company can permit and build a new facility within two years from concept to start-up, building a pipeline is another level of complexity. Acquiring the right-of-ways can take years and in some cases, is delayed or ultimately denied.

- A facility often has an economic "window of opportunity" they want to exploit with respect to a new product. They know that if they do not get that "first mover" advantage, that they will lose the opportunity to equally smart Asian firms that do not have to wait years for approval of a pipeline.

- Small chemical plants and refineries will be in serious jeopardy if they are required to build a pipeline for a new plant's expansion. Their margins are already tight, their capital budgets small, and the cost burden of a pipeline will certainly jeopardize their project plans.

- These smaller refineries are often located in remote areas of the Western U.S. where there are limited options for receiving transportation fuels from other larger refiners. The U.S. posture with regard to energy security could be further eroded by requiring pipeline projects be undertaken by these smaller refiners.

Assuming an appropriate geologic formation is proximate to a facility, the sequestration of CO_2 (EOR, saline aquifer, etc.) requires a Class 6 UIC injection well. Additional concerns include:

- The well could require years for approval, and subject the company to delays in their project, possibly causing them to miss their economic window of opportunity, thus killing their expansion plan.

- If this well is not approved by the regulatory agency charged with oversight, questions arise as to whether CO_2 still must be injected and whether or not the project can be completed.

In addition, physical plot space is often a limit at facilities and should have been considered in the Hydrogen Plant example. If a certain control requires additional equipment of a significant size, we suggest that the example be tailored to show that the control might be disqualified as infeasible.

Appendix H does not explicitly state that the user builds their list of BACT options by consulting the RACT/BACT/LEAR clearinghouse. We think the initial search for control options needs to be described more explicitly in this example.

The GHG BACT Guidelines Must Be Changed

These comments illustrate the fact that this guidance needs to be revised to reflect the comments stated above and that GHG permitting be stayed until the guidance is clarified and adjusted. There is simply too much uncertainty among all the stakeholders, and this uncertainty may cast a chill across the nation's current economic recovery. This is the first time we have ever regulated greenhouse gas emissions, and if we are to be successful, we need to have the process done right from the outset.

NPRA appreciates the opportunity to comment on this proposal. Please contact me at (202) 457-0480 if you have any questions about these comments.

Respectfully submitted,

David Friedman
Senior Director, Regulatory Affairs

“D”

Technical Support Document

Industry Overview and Current Reporting Requirements for Petroleum Refining and Petroleum Imports

Proposed Rule for Mandatory Reporting of Greenhouse Gases

Office of Air and Radiation
U.S. Environmental Protection Agency

January 30, 2009

Table of Contents

List of Exhibits

1.0. Introduction

1.1. Purpose

This document provides an overview of the petroleum industry and identifies the current federal reporting requirements of fuel suppliers, namely suppliers of petroleum products, whether refiners or importers. The analysis here is part of a larger effort to develop guidelines for mandatory reporting requirements for greenhouse gases (GHGs). In December 2007, Congress enacted an omnibus appropriations bill that directs EPA to develop and publish a rule requiring measurement and reporting of GHG emissions above appropriate thresholds in all sectors of the economy. The bill mandates that EPA publish a proposed rule within nine months and a final rule within 18 months. Understanding the information that fuel suppliers already generate and report to federal agencies is a first step in developing mandatory GHG reporting requirements.

This document focuses on firms in the petroleum industry, particularly petroleum refiners, and the various players that import petroleum products. The emphasis is on the generation of reports about volumes of petroleum products produced at U.S. refineries and petroleum product imports. The report also addresses the level of detail of data, facility definitions and boundaries, frequency of reporting, validation of reported data, and how data gaps are managed. The report presents information on the coverage of the data that are reported, key gaps in the data, business sensitivity of the data, and questions about data verification and quality assurance and control. Finally, the report discusses a number of relevant and critical aspects of the rule making such as the carbon content of petroleum products, the question of threshold, and the costs associated with monitoring and/or measuring the carbon content of products and provides information on the calculations and assumptions underlying these aspects of the rule.

Throughout the document petroleum refineries and corporate entities are mentioned by name. All data and all name references are drawn from data and reports in the public domain. While a number of sources are used the main source is the web site of the Energy Information Administration (EIA) of the U.S. Department of Energy.

1.2. Organization of this Report

To provide context for the reporting requirements of the petroleum sector, section 2 provides an overview of the industry and the role that petroleum plays in the total energy consumption of the United States. The focus is on the petroleum refining portion of the industry and on petroleum imports but summary information about other major players in the industry: producers, pipelines/terminals, and distributors is also provided. The survey of the industry begins with a statistical summary of refineries, their capacity, and their concentration, both geographic and economic. This is followed by a discussion of the petroleum industry participants, with brief discussions of each, focusing on the types of information generated in both the natural course of business as well as information developed for and reported to federal government agencies. The information typically reported to state government agencies is also identified. Included in this section is a brief description of the non-energy petroleum products such as petrochemical feedstocks, asphalt and road oil, among others.

Section 3a is where the current reporting requirements of the industry are described. It is divided into three subsections. The first address petroleum refineries, the second imports/exports, and the final subsection briefly discusses other federal sources of data.

In Section 3b, conclusions about overall gaps in the reporting requirements are reported, as well as other issues relevant to data coverage. Quality control and reliability of the data reported are also briefly addressed. Also included is a section on the data that the industry considers most sensitive. Finally Section 4 includes a discussion on the carbon factors for petroleum products natural gas liquids, and biomass and presents the default table of carbon factors along with the calculations, the sources and the methodology. The calculations supporting the rule in the area of threshold analysis are presented next, and the estimated costs.

2.0. Overview of the Petroleum Industry

2.1. The Role of Petroleum in the Economy

The United States is currently the third largest producer of crude oil in the world following Saudi Arabia and Russia. In 2006 the United States produced 8,330 thousand barrels per day (Mb/d) of total oil and 5,102 Mb/d of crude oil. The difference between the two numbers represents production of lease condensate and natural gas liquids as well as refinery gain, which in the United States ranges between six and seven percent on average. The EIA maintains a historical data set which shows that the long term trend is a steady decline in volume of production, although there have been some years of increased production as when Prudhoe Bay came on line and with the advent of the deepwater Gulf of Mexico production.

Crude oil production is surprisingly widespread and can be found in the majority of the states. The other notable fact about U.S. production is that of the almost 500,000 producing oil wells (EIA 2007) in the United States over 84 percent are classified as stripper wells[1]. However, the main and larger producers are found in PADD[2] 3 (Texas and Louisiana) and PADD 5 (California and Alaska).

On the demand side the United States is the world's largest consumer of petroleum, consuming 20,687 Mb/d in 2006. This amounts to approximately 39.8 quadrillion Btus or Quads. The difference between the consumption and the production number, even taking into account refinery gain[3] is an indication of the degree of U.S. dependence on imports. Another important fact is that of the petroleum products consumed in the

[1] Stripper wells are defined as marginal wells reaching the end of their economic life and producing between 5 to 15 barrels per day. (EIA)

[2] PADD =Petroleum Administration for Defense District, the administrative divisions of the country by which most petroleum data are reported. PADD 1 is the East Coast, PADD 2 is the Midwest, PADD 3 is the Gulf Coast, PADD 4 is the Rockies, and PADD 5 is the West Coast. There is also a PADD 6 which consists of the U.S. Virgin Islands and Puerto Rico, and a PADD 7 which consists of the Pacific Territories. A map of the main 5 PADDs is attached at the end of this document.

[3] Refinery gain is the volumetric increase in the total amount of product produced at a refinery compared to the inputs. Thus for 1 barrel of inputs output is 1.06 barrels. The level of the gain varies with the complexity of the refinery ranging from 1 percent at a topping plant to about 10 percent at a highly complex refinery.

United States over 71 percent are transportation fuels of various types (gasolines, on-road diesels, marine and locomotive diesels, aviation fuels, and bunkers).

Petroleum accounts for almost 40 percent of United States primary energy consumption, still by far the largest of the energy forms (EIA, 2006). Exhibit 1 shows the breakdown of primary energy consumption by energy form.

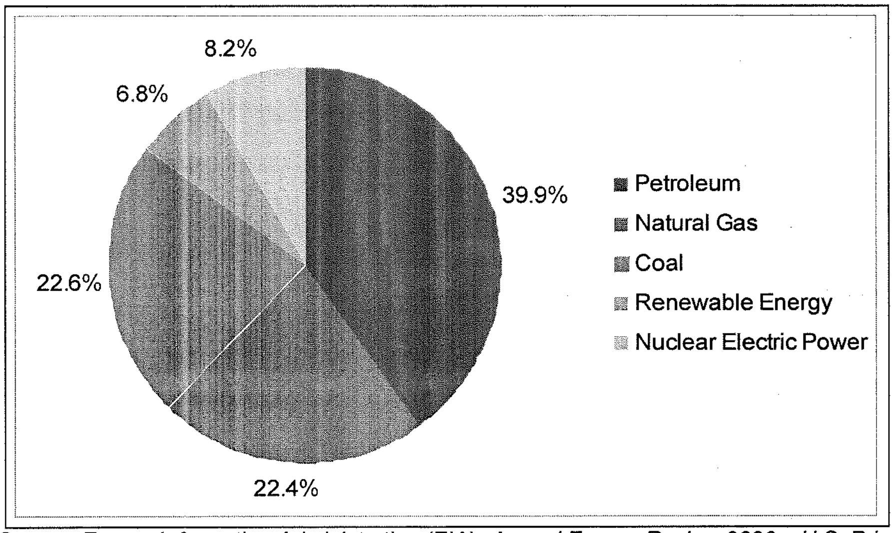
There are currently 150[4] active petroleum refineries in the United States sited in all 5 PADDs but the bulk of them are situated in the Gulf Coast and on the West Coast, the main producing areas. Looking back to the 1970s there were then over 300 refineries. However, many of those were small inefficient refineries that were opened largely because of various subsidies and crude oil price controls. The 1980s and 1990s saw a long period of refinery closings and consolidations as subsidies were ended and price controls lifted. This elimination of small, simple, and inefficient refineries and its effect is reflected by the fact that although the number of refineries has declined markedly, the atmospheric distillation capacity of the remaining U.S. refineries has steadily increased (See Exhibit 2). Petroleum refineries are extremely capital intensive, technologically sophisticated facilities with very strong economies of scale. However, small refineries can still function well in the United States if they have a captive market or produce high value added products.

The increasing complexity of the product specifications and the increasing deterioration of the world crude oil slate[5] have led to major investment in equipment that has made U.S. refineries among the most complex in the world and able to deal effectively with the worst types of crude oils (which are also the cheapest). The down side of this is that these refineries have more intensive processing, use more energy, and thus have higher emissions.

[4] As of January 1, 2008, EIA

[5] Over the past decade the global crude oil slate has become increasingly heavier and higher in sulfur which requires more intense processing to produce the clean fuels required in many countries. This is a long term trend although there are periods in which it has been temporarily reversed such as from the growth of Angolan crude oil which is generally light and low in sulfur.

Exhibit 1: 2006 Petroleum Share of Primary Energy Consumption



Source: Energy Information Administration (EIA), *Annual Energy Review 2006 – U.S. Primary Energy Consumption by Source and Sector, 2006*

Exhibit 2: Refinery Numbers and Operating Capacity Mb/d

	2003	2004	2005	2006	2007
PADD 1	1,571	1,663	1,638	1,627	1,658
	13	14	13	13	13
PADD 2	3,518	3,526	3,569	3,583	3,582
	26	26	26	26	25
PADD 3	7,708	7,881	8,068	7,464	7,990
	54	54	53	52	55
PADD 4	578	582	588	596	598
	16	16	16	16	16
PADD 5	3,109	3,107	3,144	3,152	3,171
	36	36	36	35	36
U.S. Total	16,484	16,759	17,006	16,421	16,998
	145	146	144	142	145
Source: www.eia.doe.gov/oil_gas/petroleum/info_glance/petroleum.html					

Exhibit 3 shows some of the range of crude oil imports into the United States by API gravity. As the exhibit shows the largest percentage of crude oil types that are imported into the United States fall into the heavy oil category, (<25 API gravity). At the other end of the scale, a small amount of Algerian condensate is imported into Louisiana for a few specialized refineries.

Exhibit 3: Crude Oil Imports into the United States by API Gravity Percentage of Total Crude oil Imports

API Gravity	August 07	September 07	October 07	November 07	December 07	January 08
20.0 or less	13.26	13.56	12.83	10.01	13.38	13.41
20.1 -25.0	20.84	19.83	21.3	26.17	23.38	29.05
25.1 -30.0	13.06	14.31	13.26	11.7	7.22	10.86
30.1 -35.0	26.58	28.44	28.04	30.17	30.08	25.03
35.1 -40.0	17.47	18.05	18.8	15.67	15.84	15.93
40.1 -45.0	6.48	5.37	4.08	4.56	6.54	4.24
45.1 or greater	2.29	0.44	1.69	1.73	3.56	1.48

Source: http://tonto.eia.doe.gov/nav/pet/pet_move_ipct_k_m.htm

The United States imports refined products and blending products: the number has hovered around 2 MMb/d for many years, sometime more, sometimes less. However, product imports are expected to climb over the next decade. Exhibit 4 lists imported finished products and imported gasoline blending components for a representative month, February 2008. The import portfolio includes a full range of finished products; however it is biased towards transportation fuels as the latter approximates 45 percent.[6] Transportation fuels are broken out into a number of categories. Gasoline imports are distinguished by whether they are reformulated or conventional and then they are further distinguished by any additives such as an oxygenate. Distillate fuel oil and residual fuel oil are reported by sulphur category. Petrochemicals are reported by whether they are naphtha based or otherwise.

Exhibit 4: Imports of Products into the United States, February 2008, Mb/d

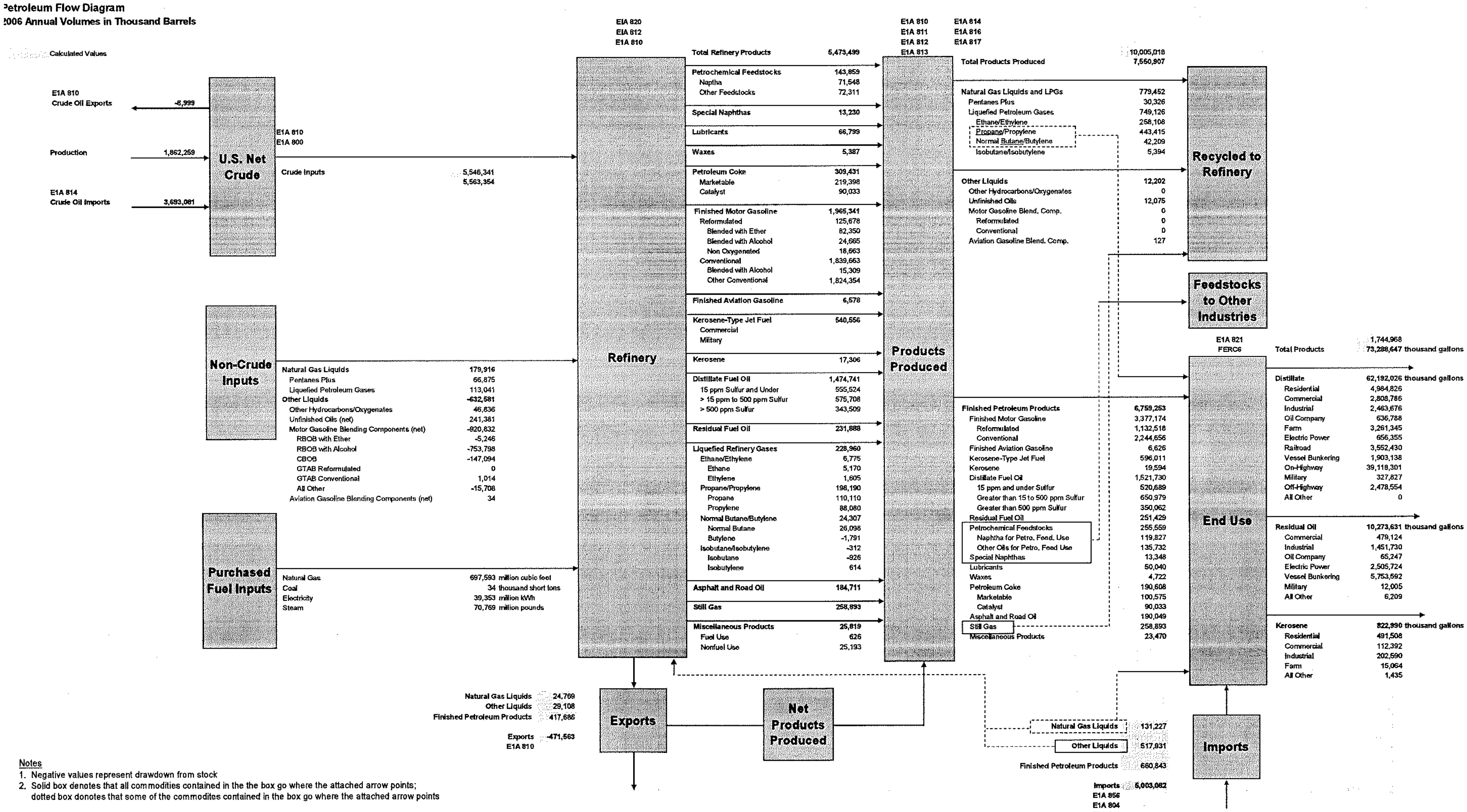
Finished Motor Gasoline (5 categories)	354
Aviation Fuels (3 categories)	101
Kerosene	2
Distillate Fuel Oil (4 categories)	248
Residual Fuel Oil (3 categories)	308
Petrochemical Feedstocks (2 categories)	171
Special Naphthas	14
Lubricants	27
Waxes	3
Petroleum Coke (Marketable)	11
Asphalt and Road Oil	34
Total	**1273**
Motor Gasoline Blending Components (6 categories)	657

Source: EIA, *Petroleum Supply Monthly*, April 2008

Exhibit 5 is a flow diagram of the petroleum industry focused around refining. The diagram shows something of the complexity of the movements and the interrelationship with other sectors.

[6] Finished Motor Gasoline 354 Mb/d, Aviation Fuels 101 Mb/d, and that portion of the Distillates that is ULSD 124 Mb/d.

Exhibit 5: Flow Diagram of the Petroleum Industry



Notes
1. Negative values represent drawdown from stock
2. Solid box denotes that all commodities contained in the the box go where the attached arrow points;
dotted box denotes that some of the commodites contained in the box go where the attached arrow points

Source: EIA Petroleum Supply Annual 2006

2.2. Structure of the Petroleum Industry

This section describes the operating components of the petroleum industry.

Producers. These are the companies that explore, drill, and produce petroleum, and in many cases, natural gas in the United States. There were approximately 13,820 operators of 497,403 oil wells in 2006. These operators range from large integrated producers with worldwide operations and interests in all segments of the oil and gas industry, to large independents, to small one or two person operations that may only have partial interest in a single well. The twenty largest producers in 2006 are shown in Exhibit 6. The 10 largest producers accounted for 2,669 Mb/d in 2006 or 53 percent of total crude oil production while the largest 20 producers accounted for 62 percent. The top 50 producers accounted for 75 percent. The remaining 13,770 accounted for the last 25 percent of crude oil production (EIA, 2006). Attached at the end of this paper is a list of the top 200 producers.

The three largest producing states are Texas (21 %), Alaska (15 %), and California (12 %). In addition, 25 percent of U.S. production comes from the Federal offshore in the Gulf of Mexico.

Exhibit 6: Twenty Largest Producers of Crude Oil in the United States in 2006

Rank	Company Name	Volume (Mb/d)
1	BP Plc	586
2	Chevron Corporation	450
3	ConocoPhillips Co	401
4	Shell Oil Co	305
5	Occidental Petroleum Corporation	285
6	Aera Energy LLC	188
7	Anadarko Petroleum Corporation	183
8	ExxonMobil Corporation	131
9	Apache Corporation	81
10	Plains Exploration & Production Co	59
Total		**2,669**
Percentage of U.S. Total		**53%**
11	Kinder Morgan Energy Partners	57
12	Amerada Hess Corporation	57
13	Dominion Resources Inc.	54
14	Noble Energy Inc.	52
15	Marathon Oil Co.	47
16	Merit Energy Co	46
17	Murphy Oil Corporation	43
18	XTO Energy Inc	40
19	Devon Energy Corporation	38
20	EOG Resources Inc	37
Total		**3,140**
Percentage of U.S. Total		**62 %**

Source; EIA 2006

Producers create and maintain extensive and accurate records on petroleum production in the normal course of business. Particular attention is paid to the lease meter, because it is at that point that royalty payments are calculated. Royalty payments must be made to landowners and other well partners. State severance taxes require the submission to state agencies of production data and sales. Federal royalty payments are made to the land management agencies and to the Minerals Management Service for offshore outer continental shelf production. At the same time, producers are excused from having to file data regularly with the Energy Information Administration (EIA). EIA's reports on production come from data collected from state agencies. State agencies are the central repositories for production data. EIA does collect sample data from producers in EIA-231 and EIA-23S, *Annual Survey of Domestic Oil & Gas Reserves.* EIA-231 is sent to a sample of large and mid size operators who report data on the field level, while EIA-23S is sent to a sample of small operators who report data on the state or geographic level. Although the focus of the forms is on reserves the survey recipients are required to report on oil, gas, and lease condensate production for the appropriate year.

Gathering Pipelines. These are pipelines that collect petroleum from wellheads in a branch and trunk system and deliver the crude oil into either a refinery or a trunk line that then moves the crude oil to a refinery. There are about 14,911[7] miles of crude oil gathering pipelines in the United States. They may be owned by the producer or the processing plant, or the affiliate of a trunk line or an independent gathering business. They charge a fee for the service where fees are negotiated between the producer and the gathering pipeline.

Gathering pipelines measure the crude oil they transport and thus have extensive records on current levels of throughput. However, only if they move over 1,000 barrels are they required to file their data with EIA in EIA-813 *Monthly Crude Oil Report*. They also must file reports with the Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS). These are relative to siting, routing, and safety issues. Gathering systems may also report to federal land management agencies and state land use agencies.

Petroleum Refiners. There are currently 150 operating petroleum refineries in the United States with a capacity of 17,000 Mb/d. As Exhibit 2 above shows capacity has been steadily increasing both at the national and at the PADD level. A new refinery has not been built in the United States for over 30 years and U.S. refiners have responded by expanding existing refineries, which is still difficult but has proved easier in terms of local permits.

A distinct characteristic of the refining sector is the high level of concentration, both geographic and economic. The geographic concentration is historic and relates to the pattern of crude oil production in the country. The economic concentration relates in part to the high capital costs and the economies of scale in refining technology. As an example unless an individual refinery has a captive market a hydrocracker would not be installed in a refinery of less than 100,000 b/d capacity.

Exhibit 7 shows the geographic concentration of refining and Exhibit 8 shows the economic concentration.

[7] *Oil & Gas Journal*, Volume 10633, September 1, 2008

Exhibit 7: Refinery Capacity in the Top 5 States
Mb/d

	2003	2004	2005	2006	2007
1. **Texas**	4,329	4,468	4,628	4,241	4,337
2. **Louisiana**	2,719	2,753	2,773	2,534	2,971
3. **California**	1,990	1,984	2,005	2,005	2,022
4. **Illinois**	878	878	896	904	904
5. **Pennsylvania**	760	760	770	770	773
Total	**10,676**	**10,843**	**11,072**	**10,454**	**11,007**
Percentage of U.S. Total	**65%**	**65%**	**65%**	**64%**	**65%**

Source: EIA

As Exhibit 7 shows 65 percent of the refining capacity in the United States is concentrated in 5 states, all of which constitute the historic production centres of the country.

Exhibit 8: Refinery Capacity of the Top 10 Refining Companies
Mb/d

	2003	2004	2005	2006	2007
1	ExxonMobil 1,808 11%	ConocoPhillips 2,186 13%	ConocoPhillips 2,198 13%	Valero 2,195 13%	Valero 2,219 13%
2	Phillips 1,711 10%	ExxonMobil 1,844 11%	Valero 2,108 12%	ConocoPhillips 1,983 12%	ExxonMobil 1,862 11%
3	BP 1,502 9%	Valero 1,696 10%	ExxonMobil 1,847 11%	ExxonMobil 1,860 11%	ConocoPhillips 1,779 10%
4	Valero 1,317 8%	BP 1,505 9%	BP 1,505 9%	BP 1,039 6%	BP 1,249 7%
5	Chevron 999 6%	Chevron 1,007 6%	Chevron 1,007 6%	Chevron 1,012 6%	Chevron 1012 6%
6	Marathon 935 6%	Marathon 935 6%	Marathon 948 6%	Marathon 974 6%	Marathon 974 6%
7	Motiva 880 5%	Motiva 887 5%	Sunoco 900 5%	Sunoco 900 5%	Sunoco 903 5%
8	Sunoco 730 4%	Sunoco 740 4%	Koch Industries 763 4%	PDV America 785 5%	Koch Industries 777 5%
9	Shell 669 4%	PDV America 640 4%	Motiva 747 4%	Koch Industries 777 5%	Motiva 762 4%
10	Conoco 566 3%	Shell 574 3%	PDV America 640 4%	Motiva 747 5%	PDV America 753 4%
Source: EIA					

The top ten refining companies currently control 72 percent of the refining capacity in the country. For the last two years the list has been topped by the large independent, Valero, which is a refining company only.

As the flow diagram (Exhibit 5) shows, refineries sit between production and consumption, but also, to some extent between natural gas processing plants and consumption. They are among the largest of the industrial energy users, using their own products, including still gas, as well as purchased natural gas and, in some places coal. Refinery consumption of electricity, steam and hydrogen is somewhat more complicated as they both purchase these products from outside the fence and self generate them.

Traditionally their purchased natural gas was used both for energy and as a feedstock for the hydrogen plant. However, Air Liquide has now built a large pipe ring in Houston through which it provides hydrogen to the Houston refineries that have, in most cases, closed down their own hydrogen plants. Trade Journals have been discussing the possibility of a similar effort by Air Liquide on the West Coast.

Increasingly refineries are also integrating with petrochemical plants. In many cases the ethylene cracker is now built among the refinery processing units so that the feedstock can swing from natural gas to naphtha to gasoil depending on the relative prices.

Refineries are among the industrial facilities that have to provide the most data to federal and state officials. They are also closely monitored for safety by both OSHA and the relevant state agencies and are closely monitored for criteria pollutants and toxic emissions. Depending on their location (whether or not a residential area has grown up around them) they may or may not continuously monitor all emissions going over the fence. Refineries provide detailed information to EIA on a monthly and annual basis largely in EIA-810 *Monthly Refinery Report* and EIA-820 *Annual Refinery Report*. These reports are mandatory and required from every refinery in the country with no exceptions. There are a plethora of other reports that they file related to their imports, to their sales, and to their stocks which are discussed in Section 3. Refineries are also required to report detailed information to state agencies. California and Texas in particular maintain substantial data on refineries.

Trunk Pipelines. These are the large diameter systems that move crude oil from producing regions to refineries or from import terminals to refineries. Not all crude oil moves through these lines as this is dependent on the location of the refinery vis-à-vis the source of crude oil. For example there are refineries in the coastal regions that receive their imported crude oil directly from tankers that off load at the refinery's own docks.

These pipelines are also the large diameter product lines that move refinery products to consumers or product imports to final consumers. Crude oil lines and product lines are completely separate. There is one line in the country that occasionally batches crude oil and products but it is the exception. Both the crude and the product lines can be intrastate or interstate.

As of 2007 there were 46,658 miles of crude oil trunk lines in the United States and about 85,666[8] miles of product lines. Major pipeline companies include Colonial Pipeline Co., Enbridge Energy LP, Marathon Pipeline LLC and Explorer Pipeline Co. Each of these companies owns several major interstate pipelines and are the top four petroleum lines in terms of trunkline traffic[9].

The major components of pipelines include the receipt and delivery meters, pump stations, and the pipe itself. Product pipelines in particular can have many receipt point meters where products are loaded up into the pipeline directly from refineries. The delivery point meters measure deliveries to other pipelines, storage, and large end users. Pipelines must operate to maintain a balance between receipts and deliveries on

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[8] *Ibid*
[9] *Oil & Gas Journal*, September 3, 2007

a daily, monthly, and annual basis. Shippers' bills are based on these meter readings and over the course of a year are reasonably accurate

Both crude and product pipelines submit information to EIA. The crude lines report on EIA-813 *Monthly Crude Oil Report* and all the product lines report on EIA-812 *Product Pipeline Report*. Product pipelines also report to EIA weekly on EIA 802-*Weekly Product Pipelines Report*. However, the product pipelines reports apply ONLY to movements between PADDS. As mentioned above crude oil lines are only obliged to file if they move more than 1,000 barrels. Both product and crude oil interstate lines are required to report to the Federal Energy Regulatory Commission (FERC) annually, U.S. FERC *Form 6: Annual Report of Oil Pipeline Companies*. Intrastate lines are required to report to their relevant state agency.

Marine Companies. A substantial amount of crude oil, unfinished oils and products moves around by tanker and barge. There is considerable inter refinery trading of crude oil and unfinished oils particularly in the U.S. Gulf that moves by barge on the intercoastal waterway. It is not uncommon during non-scheduled events such as accidents or mechanical problems or scheduled events such as annual maintenance turnarounds for refiners to trade excess unfinished product.[10] Unfinished oils can also be traded if there is an imbalance between the atmospheric distillation tower and some of the downstream processing units. For example, if the refinery is producing more naphtha than it can process the option facing it are to either sell the naphtha on the open market or to trade it to another refinery – the decision will be made based on the relative prices. Inter-company shipments from one refinery to another have to be reported to EIA on the *Monthly Refinery Report* (EIA-810) and the *Annual Refinery Report* (EIA-820).

On the East coast, imports from overseas and domestic products from the south converge on New York City and are then distributed to New England and the Mid Atlantic by barge along the East Coast Inland waterway. During part of the year substantial volumes of products move up the Mississippi by barge. All inter-PADD movements by water are required to be reported to EIA in EIA-817 *Monthly Tanker and Barge Movements between PADDs*. In addition, all marine movements and details on the type and volume of cargo are tracked and reported by the Army Corps of Engineers on Forms ENG Form 3935 and ENG Form 3925B (Shallow draft barge and tow boat operators) unless the trip is under one mile. However, it is unlikely that inter refinery trades would be less than a mile.

Terminal Operators. There are a number of different terminal groupings. There are crude oil terminals which are usually owned by refining companies and serve as a way station for crude oil that is imported or brought long distances for their refineries. In terms of petroleum products there are terminals that are owned by refineries and a large number of independent terminals that store both domestic and imported products depending on their location. There are also at least 280 terminals at which additives, blending stock and biofuels are blended with gasolines.

[10] This trading goes on on a regular basis. For example the Hovensa refinery in the U.S. Virgin Islands sends large volumes of unfinished oils to a plant in Port Reading, New Jersey which does not have an atmospheric distillation tower but does have a vacuum distillation tower and other processing units.

There are two sets of reports that terminal operators have to make to EIA, Bulk Terminals must report weekly on EIA-801 *Weekly Bulk Terminal Report* and monthly on EIA-811 *Monthly Bulk Terminal Report*. Specialized terminals, where gasoline blending takes place, report weekly on EIA-805 *Weekly Terminal Blenders Report* and monthly on EIA-815 *Monthly Terminal Blenders Report*. In addition, all bulk terminals and bulk carriers (pipeline and marine) are required to file information on their product volumes and movements to the IRS under the Excise Summary Terminal Reporting System (ExSTARS) program. This is a program that tracks all products that come into and out of bulk terminals and also tracks the destination of the products once they leave the terminal.

Importers. Substantial volumes of petroleum imports reach the United States. There is, however, a difference in both the pattern and players between crude oil imports and product imports. Most crude oil imports (and unfinished oils) are imported by the oil companies, with an occasional trader making an appearance. The crude oil comes in either directly to the refiner's marine terminal or to the terminals of the major crude oil pipelines such as Capline. Canadian crude oil enters the northern tier of the United States by pipeline, with Eastern Canadian offshore crude oil moving to the East Coast refiners by tanker. Crude oil is only used by refiners. Finished products on the other hand, can come in wherever there is a terminal with the offloading and tankage requirements. The universe of importers is different as well. Year to year it can vary considerable. The marketing arms of the oil companies import products, as do traders, petrochemical/chemical companies, propane distributors, ethanol companies, utilities on the East Coast, and there have even been times in the past during bad winters when states and local governments have directly imported heating oil.

There is a good deal more information about the origin of the crude oil that is imported into the United States than is known about refined products imports. Exhibit 9 shows the quantity of foreign crude oil imported into the 5 PADDs and Exhibit 10 shows the top 5 countries of origin. Exhibit 11 shows imports of products into the 5 PADDs.

Exhibit 9: Quantity of Crude Oil imported by PADD
Million barrels and % of Total Crude Used

	2003	2004	2005	2006	2007
PADD 1	579	567	586	547	543
	98.9%	99.2%	99.1%	98.9%	99.2%
PADD 2	349	391	367	412	410
	68.9%	71.9%	70.4%	71.9%	71.1%
PADD 3	2,156	2,284	2,236	2,187	2,164
	65.0%	67.4%	68.6%	67.9%	67.5%
PADD 4	120	111	121	119	120
	53.3%	49.7%	49.5%	47.8%	47.9%
PADD 5	323	339	386	428	419
	33.7%	36.1%	40.3%	45.2%	45.2%
U.S. Total	3,528	3,692	3,696	3,693	3,656
	63.0%	65.2%	66.3%	66.6%	66.4%
Source: EIA					

Exhibit 10: Crude Oil imports by Top 5 Countries of Origin and by PADD MMBbls

PADD 1	2003	2004	2005	2006	2007
1	Nigeria 127	Nigeria 159	Nigeria 172	Nigeria 162	Nigeria 145
2	Angola 82	Canada 72	Canada 78	Canada 77	Canada 93
3	Saudi Arabia 78	Saudi Arabia 63	Saudi Arabia 68	Saudi Arabia 67	Saudi Arabia 60
4	Canada 77	Angola 58	Venezuela 57	Venezuela 56	Venezuela 54
5	United Kingdom 45	Venezuela 43	Angola 53	Angola 54	Angola 38
PADD 2	2003	2004	2005	2006	2007
1	Canada 331	Canada 369	Canada 358	Canada 411	Canada 409
2	Nigeria 9	Nigeria 14	Angola 3		
3	United Kingdom 2	Colombia 3	Colombia 2		
4	Saudi Arabia 2	Angola 2	Nigeria 2		
5	Norway 2	United Kingdom 1	Norway 1		
PADD 3	2003	2004	2005	2006	2007
1	Mexico 538	Mexico 555	Mexico 540	Mexico 553	Mexico 498
2	Saudi Arabia 458	Venezuela 430	Venezuela 392	Venezuela 356	Saudi Arabia 373
3	Venezuela 400	Saudi Arabia 390	Saudi Arabia 341	Saudi Arabia 345	Venezuela 360
4	Nigeria 167	Nigeria 221	Nigeria 217	Nigeria 215	Nigeria 244
5	Iraq 132	Iraq 182	Iraq 152	Iraq 142	Algeria 131
PADD 4	2003	2004	2005	2006	2007
1	Canada 120	Canada 111	Canada 121	Canada 118	Canada 120
PADD 5	2003	2004	2005	2006	2007
1	Saudi Arabia 92	Saudi Arabia 93	Saudi Arabia 115	Saudi Arabia 105	Saudi Arabia 93
2	Ecuador 39	Iraq 57	Ecuador 69	Ecuador 72	Iraq 60
3	Iraq 38	Ecuador 51	Iraq 39	Iraq 59	Ecuador 56
4	Canada 24	Canada 32	Canada 32	Canada 38	Canada 46
5	Argentina 20	Argentina 19	Mexico 20	Angola 24	Angola 33
U.S. Total	2003	2004	2005	2006	2007
1	Saudi Arabia 630	Canada 591	Canada 596	Canada 655	Canada 679
2	Mexico 573	Mexico 585	Mexico 567	Mexico 576	Saudi Arabia 526
3	Canada 566	Saudi Arabia 547	Saudi Arabia 525	Saudi Arabia 517	Mexico 514
4	Venezuela 432	Venezuela 475	Venezuela 451	Venezuela 417	Venezuela 419
5	Nigeria 304	Nigeria 395	Nigeria 393	Nigeria 379	Nigeria 395
Source: EIA					

Importers of foreign crude oil and products file a number of different reports with EIA:

- EIA 814 *Monthly Imports Report* – crude oil and products
- EIA 804 *Weekly Imports Report* – crude oil and products
- EIA 856 *Monthly Foreign Crude Oil Acquisition Report*—companies importing more than 500 MB per month
- EIA 14 – *Refiner's Monthly Cost Report* – crude oil only.

EIA also puts the raw import data on its website (*Company Imports* from EIA-814). Crude oil imports are reported by batch, by volume, by sulphur content and API gravity, by country of origin, by importing refinery, and by using refinery should that be different. Using this data one can determine what crude oils are being imported by what refinery. However, in terms of the quality a certain amount of care must be exercised. Many countries export what they call an "export blend" which is composed of a combined stream of crude oils. The component crude oils and their proportions can change over time, thus changing the quality of the crude imported.

Product imports are reported by country of origin and in a few cases (for motor gasoline blending components and unfinished oils) the user and the place of use are reported. However, in most cases all that is known is the port of entry and the port of origin. In many cases there is no way of further tracing the product. Product may be drawn down from stocks in Rotterdam and, if the product is fungible, be mixed with similar products from numerous sources.

Note that refiners that export products are required to file Form 7525-V *Shipper's Export Declaration* with the Department of Commerce.

Exhibit 11: Imports of Finished Products by PADD
MMBbls

PADD 1	2003	2004	2005	2006	2007
All gasoline (including blending components)	285.3	306.6	337.6	355.9	354.5
Distillate fuel oil, <= 15 ppm sulfur	0.0	7.9	0.6	30.4	46.9
Distillate fuel oil, > 15 ppm <= 500 ppm sulfur	42.1	33.5	45.4	19.9	2.1
Distillate fuel oil, > 500 ppm sulfur	70.8	61.0	60.2	58.9	35.6
Kerosene and kerosene-type jet fuel	26.2	18.6	39.0	34.8	36.6
Residual fuel oil, < 0.31% sulfur	14.7	24.6	28.4	6.3	12.0
Residual fuel oil, 0.31-1.00% sulfur	30.7	42.9	48.9	21.4	14.6
Residual fuel oil, > 1.00% sulfur	50.0	54.6	69.9	60.5	51.3
Petrochemical feedstocks	3.9	2.7	1.4	1.3	1.6
All other petroleum products	62.7	92.2	99.2	118.6	114.1
PADD 2	**2003**	**2004**	**2005**	**2006**	**2007**
All gasoline (including blending components)	0.7	0.7	1.0	0.3	0.8
Distillate fuel oil, <= 15 ppm sulfur	0.0	0.0	0.0	0.2	1.3
Distillate fuel oil, > 15 ppm <= 500 ppm sulfur	2.1	1.8	1.1	1.7	0.6
Distillate fuel oil, > 500 ppm sulfur	0.6	0.7	0.4	0.4	0.3
Kerosene and kerosene-type jet fuel	0.2	0.4	0.1	0.0	0.0
Residual fuel oil, < 0.31% sulfur	0.1	0.0	0.0	0.0	0.0
Residual fuel oil, 0.31-1.00% sulfur	0.6	0.8	1.1	0.8	1.4
Residual fuel oil, > 1.00% sulfur	0.5	0.8	1.0	1.2	1.2
Petrochemical feedstocks	0.4	0.5	1.3	2.6	2.0
All other petroleum products	34.5	40.6	44.0	44.6	38.4
PADD 3	**2003**	**2004**	**2005**	**2006**	**2007**
All gasoline (including blending components)	17.4	16.2	46.3	40.7	32.3
Distillate fuel oil, <= 15 ppm sulfur	0.0	1.1	0.0	3.6	2.7
Distillate fuel oil, > 15 ppm <= 500 ppm sulfur	0.3	0.9	3.5	1.0	0.2
Distillate fuel oil, > 500 ppm sulfur	0.6	2.0	0.6	2.0	6.0
Kerosene and kerosene-type jet fuel	0.3	0.2	6.1	2.6	1.4
Residual fuel oil, < 0.31% sulfur	1.8	5.4	2.9	2.2	4.2
Residual fuel oil, 0.31-1.00% sulfur	3.7	6.4	12.6	5.0	15.0
Residual fuel oil, > 1.00% sulfur	4.2	7.8	13.0	13.3	23.2
Petrochemical feedstocks	80.8	103.1	110.4	107.0	84.6
All other petroleum products	136.7	183.6	230.4	251.1	222.8
PADD 4	**2003**	**2004**	**2005**	**2006**	**2007**
All gasoline (including blending components)	0.2	0.2	0.1	0.0	0.0
Distillate fuel oil, <= 15 ppm sulfur	0.0	0.0	0.0	0.4	2.0
Distillate fuel oil, > 15 ppm <= 500 ppm sulfur	2.7	3.4	2.1	2.3	0.8
Distillate fuel oil, > 500 ppm sulfur	0.2	0.5	0.2	0.3	0.2
Kerosene and kerosene-type jet fuel	0.1	0.2	0.2	0.2	0.1
Residual fuel oil, < 0.31% sulfur	0.0	0.0	0.0	0.0	0.0
Residual fuel oil, 0.31-1.00% sulfur	0.0	0.0	0.0	0.0	0.0
Residual fuel oil, > 1.00% sulfur	0.0	0.0	0.0	0.0	0.0
Petrochemical feedstocks	0.0	0.3	0.0	0.0	0.0
All other petroleum products	3.3	4.2	3.9	5.4	5.0
PADD 5	**2003**	**2004**	**2005**	**2006**	**2007**
All gasoline (including blending components)	19.5	22.9	22.0	21.0	35.0
Distillate fuel oil, <= 15 ppm sulfur	0.0	1.6	0.9	6.2	9.6
Distillate fuel oil, > 15 ppm <= 500 ppm sulfur	2.1	4.0	3.2	3.1	1.3
Distillate fuel oil, > 500 ppm sulfur	0.2	0.6	1.9	2.6	0.5
Kerosene and kerosene-type jet fuel	15.2	27.9	26.6	31.7	42.2
Residual fuel oil, < 0.31% sulfur	1.6	2.5	2.6	3.1	0.5
Residual fuel oil, 0.31-1.00% sulfur	1.4	1.3	1.2	1.6	1.6
Residual fuel oil, > 1.00% sulfur	10.2	9.0	11.7	12.5	10.4
Petrochemical feedstocks	0.2	0.0	0.1	0.8	0.6
All other petroleum products	19.7	22.7	26.7	30.4	31.6

Source: EIA

Marketers. Petroleum marketers purchase products either directly from refiners or indirectly from terminal operators. There are approximately 8,000 independent petroleum marketers in the country. Like all other sectors of the industry the last decade has brought increasing consolidation in this sector as well. The independent marketers do not submit reports to EIA. They are indirectly tracked through the refinery marketing reports in which refiners are required to report sales of products directly to end users and their sales to other marketers.

Non-Energy Use of Petroleum Products. The largest volume of petroleum products are combusted for energy, either as transportation fuels or as furnace or boiler fuels. Some products are consumed for non-energy uses. ICF has conducted an intensive study for non-energy uses for EPA's *Inventory of Greenhouse Gases and Sinks.*[11] The petroleum products consumed for non-energy use are shown in Exhibit 12.

Exhibit 12: Consumption of Petroleum Products for Non-Energy Uses
TBtu

	2003	2004	2005	2006
Asphalt & Road Oil	1,219.5	1,303.8	1,323.2	1,225.6
Distillate Fuel Oil	11.7	11.7	11.7	11.7
LPG	1,437.8	1,436.7	1,442.0	1,491.8
Lubricants	159.0	161.0	160.2	130.6
Pentanes Plus	158.3	156.5	146.0	105.1
Naphtha (<401 F)	573.4	687.9	678.6	592.9
Other Oil (>401 F)	501.0	547.8	518.7	573.4
Still Gas	59.0	63.5	67.7	122.3
Petroleum Coke	76.9	161.3	145.0	178.7
Special Naphtha	75.7	47.2	60.9	68.7
Waxes	31.0	30.8	31.4	25.2
Miscellaneous Products	126.0	113.4	112.8	133.2

CO_2 emissions occur from non-energy uses via several pathways. When a product is manufactured emissions may occur when producing plastics or rubber from petroleum derived feedstocks, for example. Emissions may also arise when a product is used, such as solvent use. Overall, looking at all non-energy uses of petroleum feedstocks about 62 percent of the carbon contained in the non-energy petroleum feedstocks is stored in the products with the remaining 38 percent emitted at various stages. Exhibit 13 shows the estimated carbon stored and CO_2 emissions for 2006 of non-energy use of petroleum products in the United States. These emissions constituted less than 2 percent of overall fossil fuel emissions, a percentage that has not appreciably changed since 1990.

Summary. In every sector of the petroleum industry the flow of crude oil and petroleum is closely monitored since it is the source of revenue. Some of the data are reported to federal government and some to state governments. In every case, however, data are routinely collected, aggregated, and verified as the basis for executing sales and billing customers.

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[11] http://www.epa.gov/climatechange/emissions/usinventoryreport.html

Exhibit 13: 2006 Non-Energy use Petroleum Product Consumption, Storage and Emissions

	Non-Energy Use (TBtu)	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2)
Asphalt & Road Oil	1,225.6	25.3	0.0	0.0
Distillate Fuel Oil	11.7	0.1	0.1	0.4
LPG	1,491.8	15.4	9.6	35.3
Lubricants	130.6	0.2	2.4	8.8
Pentanes Plus	105.1	1.2	0.7	2.7
Naphtha (<401 F)	592.9	6.6	4.1	15.2
Other Oil (>401 F)	573.4	7.0	4.4	16.1
Still Gas	122.3	1.3	0.8	3.0
Petroleum Coke	178.7	2.5	2.5	9.1
Special Naphtha	68.7	0.8	0.5	1.9
Waxes	25.2	0.3	0.2	0.8
Miscellaneous Products	133.2	0.0	2.7	9.9

3a.0. Industry Federal Reporting Requirements

This section focuses on sectors identified as points of monitoring of petroleum: refining, imports, and exports. The following discussion is based on information gathered on current reporting requirements and presents a discussion of the reporting matrix spreadsheets compiled as background for the rule and attached at the end of the document. The discussion is focused on the reporting requirements most relevant to the determination of an accurate accounting of the flow of commodities through the nation's petroleum infrastructure.

Each sector is structured in a similar fashion: the key reporting obligations by agency and reporting form are discussed; the key questions EPA has identified for evaluating the suitability of the reporting requirement as a basis for the Agency's mandatory monitoring system are then discussed. These questions include:

- What is reported?
- Is the reporting tied to a facility or entity at a facility?
- What is the threshold for reporting?
- What is the frequency of reporting?
- How is the data developed?
- What are the verification/certification, QA/QC methods?
- How public is the information?
- Where are the gaps in sector coverage that would lead to un-accounted for volumes?

The summary matrices are included in the Appendix.

3a.1. Refineries

Energy Information Administration

EPA receives reports from refineries related to the specifications of transportation fuels, but the EIA is the only federal agency that receives extensive physical and financial information reports from refineries. Monthly and annual reports are required for all refineries, while weekly reports are required for a subset of refineries selected by the EIA; sampling procedure assures coverage of 90 percent of the data. The weekly report (EIA-800) includes only quantities and ending stocks for inputs and products. The monthly report (EIA-810) includes information on refinery input and capacity, sulfur content and API gravity of crude oil, and detailed stock information on a comprehensive list of inputs and products. It should be noted that for the weekly and monthly reports, stocks in the custody of the refinery are reported regardless of ownership and quantities must be at least 500 barrels to be reported (rounded to 1 whole-number thousand-barrel unit).

Report Name: EIA-810 Monthly Refinery Report	
What is reported	Input and capacity (thousand barrel), crude quality, production and stock information (thousand barrel)
Who is reporting	All refinery operators
What is the threshold for reporting	No minimum; quantities at least 500 barrels due to rounding
What is the reporting frequency	Monthly
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Throughout refinery, refinery gate
What are the verification/certification & QA/QC methods	Some of the data could be reconciled against the weekly report; sanctions for failure to comply
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

The annual refinery form (EIA-820) reports on an almost entirely different set of information. In addition to atmospheric crude oil distillation capacity, which is also reported on a monthly basis, the annual form requires the quantity of fuel purchased and consumed at the refinery, receipts of crude oil by method of transportation, downstream charge capacity, production capacity, and storage capacity.

Report Name: EIA-820 Annual Refinery Report	
What is reported	Purchased fuel, crude oil receipts (thousand barrel)
Who is reporting	All refinery operators
What is the threshold for reporting	No minimum
What is the reporting frequency	Annual
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Throughout refinery, refinery gate
What are the verification/certification & QA/QC methods	Some of the data could be reconciled against the monthly report; sanctions for failure to comply
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

Atmospheric crude oil distillation capacity and downstream charge capacities for individual refineries as well as other information in aggregated form are publicly available at the Refinery Capacity Report page on the EIA website.

Refineries that produce oxygenates as part of their product mix are required to submit a monthly oxygenate report (EIA-819), which is mandatory for all facilities that produce oxygenates and not limited to refineries. The form reports production and stock information of various oxygenates, including fuel ethanol, ETBE and MTBE, and motor gasoline blending components, by PADD with a U.S. total. Like the monthly refinery report, stocks in the custody of the facility are reported regardless of ownership and the reporting unit is thousand barrels, so quantities below 500 barrels will not be reported due to rounding to the nearest whole number.

Report Name: EIA-819 Monthly Oxygenate Report	
What is reported	Production and stock information of oxygenates
Who is reporting	Operators of all facilities that produce oxygenates
What is the threshold for reporting	No minimum; quantities at least 500 barrels due to rounding
What is the reporting frequency	Monthly
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Throughout facility
What are the verification/certification & QA/QC methods	Sanctions for failure to comply
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

Aggregated data from EIA-819 is publicly available at the Monthly Oxygenate Report page on the EIA website.

Environmental Protection Agency

EPA has several reporting programs that capture the flow of petroleum transportation products. Three forms of note are part of the Reformulated Gasoline and Anti-Dumping Reporting Program; one additional form falls under the Diesel Fuel Reporting Program. A complete list of reporting programs and forms is available at www.epa.gov/otaq/regs/fuels/forms.htm.

The Anti-Dumping Program Annual Report (EPA Form 3520-20H) is required for producers and importers of reformulated gasoline (or RBOB), conventional gasoline or applicable blendstocks. Despite the criteria for reporting, the only volume reported is for gasoline.

Report Name: EPA Form 3520-20H Anti-Dumping Program Annual Report	
What is reported	Total volume of conventional gasoline (gallon)
Who is reporting	Producers and importers of conventional gasoline
What is the threshold for reporting	No minimum
What is the reporting frequency	Annual
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Refinery gate; pipeline imports: border point; marine imports: offloading
What are the verification/certification & QA/QC methods	Sanctions for failure to comply; auditing requirements for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

Additional EPA forms of the Reformulated Gasoline Program Emissions Performance Averaging reporting subgroup are required for producers and importers of reformulated gasoline or RBOB only.

Report Name: EPA Form 3520-20L RFG Program NO_x Emissions Performance Averaging Report EPA Form 3520-20M RFG Program VOC Emissions Performance Averaging Report	
What is reported	Total volume of reformulated gasoline or RBOB (gallon)
Who is reporting	Producers and importers of reformulated gasoline or RBOB (except CA)
What is the threshold for reporting	No minimum
What is the reporting frequency	Annual
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Refinery gate; pipeline imports: border point; marine imports: offloading
What are the verification/certification & QA/QC methods	Sanctions for failure to comply; auditing requirements for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office; independent laboratory sampling
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	CA data

In addition to Reformulated Gasoline and Anti-Dumping Reporting, the Diesel Fuel Reporting Program collects volumetric data on the flow of diesel fuel. The Designate & Track Total Volume Report is required separately for each facility and for each designation of fuel. Volumes are reported for diesel fuel received, delivered, produced, and imported. Stock information is reported in the form of beginning and ending inventory.

Report Name: EPA Form DSF0600 Designate & Track Total Volume Report	
What is reported	Volume of diesel fuel received, delivered, produced, imported (gallon); beginning and ending inventory (gallon)
Who is reporting	Facilities handling diesel fuel including refiners and importers (except CA)
What is the threshold for reporting	No minimum
What is the reporting frequency	Annual
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Refinery gate; pipeline imports: border point; marine imports: offloading
What are the verification/certification & QA/QC methods	Sanctions for failure to comply; random in-person audit by EPA's enforcement office
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	CA data

Information submitted to EPA is subject to random in-person audits conducted by EPA's enforcement office. In addition, there are penalties of up to $32,500 per day per violation for non-compliance with EPA's fuel regulations, including failure to report and reporting false information.

Summary

Refinery reporting to the EIA appears to capture the flow of petroleum commodities through the U.S. refinery system with no apparent gaps in reported data due to mandatory reporting requirement for all refiners. Inputs to the refinery are reported in great detail as are the outputs. Products are reported in detail; particularly any product that by law is sulphur constrained (e.g. diesel < 15ppm, < 500 ppm, etc.). Any products recycled within the refinery are also reported as is the fuel used within the refinery.

Relevant information reported to EPA is confined to gasoline and diesel volumes only, though there are no apparent gaps in reporting due to mandatory reporting requirements for all refiners that the produce the specified fuels. It should be noted however that most reporting requirements for diesel fuel volumes under the Designate and Track program will sunset in 2014, leaving significant gaps in diesel volume data.

The annual Worldwide Refinery Survey published by the *Oil & Gas Journal* (OGJ) is a potentially useful resource. The OGJ also publishes the Nelson Complexity Factor for all U.S. refineries. This is actually an evaluation of the capital expenditures at the refineries for processing units, but it is accepted as a surrogate for the complexity of the individual refineries. There is also the Solomon Benchmarking Surveys which compare refineries on the basis of best practices in a number of areas. These are proprietary surveys; however, the OGJ complexity factor surveys can be purchased.

3a.2. Imports

Energy Information Administration

The EIA is the only federal agency that collects reported data on petroleum imports at a level of detail beyond that of the general customs import document. (Department of Homeland Security, U.S. Customs and Border Protection, CBP Form 7501).

The Monthly Imports Report (EIA-814) is required for all importers of record who import crude or petroleum products into the 50 States and the District of Columbia from foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions. The information reported is shipment-specific; each entry on the form asks for type of commodity, port of entry, country of origin, quantity in thousand barrels, sulphur content by weight, API gravity (crude oil only), and the name and location of the processing company (crude and unfinished products). Transactions with identical details except quantity may be combined and reported on one line. All transactions of at least 500 barrels are reported (as with the refinery forms, due to rounding to the nearest whole-number thousand-barrel unit). Volumetric data is metered at import points: at the border for imports via pipeline and at offloading for marine imports.

Report Name: EIA-814 Monthly Imports Report	
What is reported	Quantity of imported commodity (thousand barrel), sulphur content, API gravity (crude only)
Who is reporting	Importers of record
What is the threshold for reporting	Transactions of fewer than 500 barrels not reported due to rounding; virtually all
What is the reporting frequency	Monthly
How are the reported data developed	Metering and from foreign supplier
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Pipeline, at border; marine, at offloading
What are the verification/certification & QA/QC methods	Check against CBP Form 7501 for consistency; sanctions for failure to comply
Is the data public or restricted	Unrestricted
Where are the gaps in the data reported	Transactions of fewer than 500 barrels

"Importers of Record" are defined by Customs as the owner or purchaser of the goods being imported, or a licensed customs broker designated by the owner or purchaser. The EIA follows the same rules as the Customs which are defined in the various laws governing imports in general.

The form captures nearly all volumes imported into the U.S., as transactions of major products rarely have volumes below the reporting threshold. Data collected on EIA-814 is publicly available at the Company Level Imports page on the EIA website.

Since all importers of crude oil and petroleum products are required to file EIA-814, which reports shipment-specific information, it would be redundant to review import records from the U.S. Customs and Border Protection (CBP), which contain the same set of data points with regards to crude and petroleum products, except in more general (as opposed to petroleum-specific) terms and at a lower level of detail. Indeed, the EIA checks its data against that from CBP Form 7501 ("Entry Summary") for consistency and uses the CBP data to identify companies that are not in the EIA data for reasons including having imported volumes below the reporting threshold.
The Weekly Imports Report (EIA-804) tracks imports activity by PADD for a list of items that includes crude oil, various formulations of finished motor gasoline, distillates of various sulphur content, and blendstocks, as well as crude imports by country of origin. The EIA-804 is required for selected importers of record who import crude or petroleum products into the 50 States and the District of Columbia from foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions. As done with the weekly refinery report, companies are selected into the EIA weekly sample according to a procedure

that assures 90 percent coverage. There is no threshold for reporting for this weekly form; importers selected into the sample must report regardless of quantity imported. The information reported on EIA-804 is not publicly available in its reported form, but essentially all of that data is reported on the monthly EIA-814, which is more comprehensive and whose data is publicly available as Company Level Imports.

The Monthly Foreign Crude Oil Acquisition Report (EIA-856) is required for all firms reporting data as of June 1982 and all firms that "acquired more than 500,000 barrels of foreign crude oil in the report month for importation into the United States." The report includes summary information (total acquisition and offshore inventories) and transaction-specific information (country of origin, crude type, gravity, date and port of loading and landing, vessel or pipeline name, volume, acquisition price, landed cost, etc.).

Report Name: EIA-856 Monthly Foreign Crude Oil Acquisition Report	
What is reported	Crude type, API gravity, volume (bbl)
Who is reporting	Importers of record
What is the threshold for reporting	500,000 barrels of foreign crude acquired for the report month
What is the reporting frequency	Monthly
How are the reported data developed	Metering and from foreign supplier
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Pipeline, at border; marine, at offloading
What are the verification/certification & QA/QC methods	Check against CBP Form 7501 for consistency; sanctions for failure to comply
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	Firms that acquired fewer than 500,000 barrels for importation for the report month are not required to file

The EIA estimates that 90% of crude imports is accounted for, while the remaining 10% is not covered by the reporting requirement. The information reported is publicly available only in aggregated form.

The volume reported on EIA-856 is the volume acquired for importation (and not the volume imported). The EIA included this clarifying note in the instructions for the form:

> Since the EIA-856 is filled on a cargo-specific basis, it is implicit that the reported acquisitions will have been loaded by the time the report was filed. In cases where foreign crude oil was acquired but not loaded by the time the report was filed, those parcels should be reported as soon as cargo-specific data are available (i.e., presumably when the volumes are loaded).

The Refiners' Monthly Cost Report (EIA-14) collects volumetric data on crude going into refineries. Mandatory for all refiners, the EIA-14 reports, separately for domestic and imported crude, total cost and total volume of crude oil acquired by PADD. This information is available on the EIA website in the form of Refiner Acquisition Cost of Crude Oil (RAC), which is aggregated from data reported on EIA-14.

Report Name: EIA-14 Refiners' Monthly Cost Report	
What is reported	Volume of imported crude oil acquired (thousand barrel)
Who is reporting	Firms that refine crude oil
What is the threshold for reporting	500,000 barrels of foreign crude acquired for the report month

What is the reporting frequency	Monthly
How are the reported data developed	Metering
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Refinery gate
What are the verification/certification & QA/QC methods	Check against CBP Form 7501 for consistency; sanctions for failure to comply
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

Imported volumes reported on EIA-804, EIA-856 and EIA-14 are checked against EIA-814 for consistency.

Environmental Protection Agency

EPA has several reporting programs that capture the flow of petroleum fuels handled by refiners and importers. The EPA forms documented in the preceding section ("Refineries") are applicable to both refiners and importers. Please refer to the preceding section for information on some of those forms.

An additional form in the Reformulated Gasoline and Anti-Dumping Reporting Program that applies to registered foreign refiners only is the Load Port/Port of Entry Independent Sampling, Testing and Refinery/Importer Identification Form (EPA Form 3520-27). Data submitted on this form includes foreign refinery registration information, importer registration information, vessel information and gasoline volume. The form is required for each occasion certified foreign refinery gas (FRGAS) is loaded onto a vessel for transport into the U.S.

report Name: EPA Form 3520-27 Load Port/Port of Entry Independent Sampling, Testing and Refinery/Importer Identification Form	
What is reported	Foreign refinery registration number, importer registration number and information, vessel information, gasoline volume (gallon)
Who is reporting	Registered foreign refiners who opt in
What is the threshold for reporting	No minimum
What is the reporting frequency	Per shipment
How are the reported data developed	Metering and operating data
Are reports mandatory or voluntary	Submissions are mandatory for foreign refiners who opt in
What is the facility level of the reporting	At offloading
What are the verification/certification & QA/QC methods	Sanctions for failure to comply; random in-person audit by EPA's enforcement office; independent laboratory sampling at port of entry
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

Information submitted to the EPA is subject to random in-person audits conducted by EPA's enforcement office. In addition, there are penalties of up to $32,500 per day per violation for non-compliance with the EPA's fuel regulations, including failure to report and reporting false information.

Summary

The mandatory reporting of information on imports in the form of EIA-814 appears to capture the flow of petroleum commodities into the U.S. with gaps only due to rounding.

EIA-856 and EIA-14 are dedicated to capturing the flow and usage of crude oil. These are potentially good resources in addition to EIA-814 should the focus for monitoring fall on crude oil.

EPA's information collection mechanisms on imports of gasoline and diesel are largely shared with those for refiners, and the information collected is generally confined to volumes only. There are no apparent gaps in reporting due to mandatory reporting requirements for all refiners. Including foreign refiners who choose to opt in, that produce the specified fuels.

3a.3. Exports

Federal Energy Regulatory Commission

The EIA does not have reporting forms for petroleum exports and obtains the data that it publishes from the Census Bureau. The Shipper's Export Declaration (Commerce Form 7525-V) is a general-purpose export form that is required for petroleum exports to most destinations. Aggregated statistics can be obtained from the Census Bureau's monthly reports (EM-522 and EM-594), which are not publicly available.

Report Name: Commerce Form 7525-V Shipper's Export Declaration	
What is reported	Commodity type (Schedule B number), quantity (bbl)
Who is reporting	Exporters
What is the threshold for reporting	No minimum
What is the reporting frequency	Per shipment
How are the reported data developed	Metering
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Pipeline, at border; marine, at loading
What are the verification/certification & QA/QC methods	Unknown
Is the data public or restricted	Aggregated data available but not public
Where are the gaps in the data reported	SEDs are not required for exports from the U.S. to U.S. possessions other than Puerto Rico and the Virgin Islands

3a.4. Others

In this section a variety of federal reporting requirements that shed light on throughputs in other sectors along the petroleum supply chain are discussed.

Minerals Management Service

MMS-4054A "Oil and Gas Operations Report, Part A – Well Production (OGOR-A)" reports production volumes by well. The report is filed monthly by all MMS lessees, i.e., Federal offshore and Federal/Indian onshore; a separate report must be filed for each lease. Historical data through January 2008 is available at the MMS website.

MMS-2058 "Production Allocation Schedule Report (PASR)" is required for operators of facility or measurement point handling production from Federal offshore.

Report Name: MMS-4054A (OGOR-A), MMS-4058 (PASR)	
What is reported	Volumes (bbl)
Who is reporting	All MMS lessees (OGOR); All facilities handling Federal offshore production (PASR)
What is the threshold for reporting	No minimum
What is the reporting frequency	Monthly
How are the reported data developed	Metering
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Lease meters
What are the verification/certification & QA/QC methods	Compliance Asset Management, a division of MMS, verifies the volumetric data against those reported for royalty purpose on MMS-2014.
Is the data public or restricted	Historical OGOR data publicly available; Offshore Minerals Management (OMM) has complete access to PASR data
Where are the gaps in the data reported	None apparent

Army Corps of Engineers

The Army Corps of Engineers collects data on domestic marine movements. There are two forms concerning freight carried: Form 3925 is the general form and Form 3925B may be substituted for shallow draft inland traffic. Neither form is petroleum-specific.

Report Name: ENG Forms 3925 and 3925B Vessel Operation Report	
What is reported	Commodity type, quantity (ton)
Who is reporting	All domestic operators engaged in commercial activity on navigable waters
What is the threshold for reporting	Trips of fewer than one mile are not required to be reported; virtually all
What is the reporting frequency	Monthly
How are the reported data developed	Metering
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Ports
What are the verification/certification & QA/QC methods	Some reconciliation of dock receipts; sanctions for failure to comply
Is the data public or restricted	Aggregated data public
Where are the gaps in the data reported	None apparent

Federal Highway Administration

The Federal Highway Administration collects consumption data from state agencies that collect the motor-fuel tax for their respective states. States are required to submit Form FHWA-551M on a monthly basis. The volumetric data, which is based on tax record and submitted in aggregated form, is publicly available.

3b.0. Data Gaps and Quality

In this section the observed gaps in the reporting requirements are discussed and suggestions for alternatives for acquiring missing data are presented. Similarly, quality control of the accuracy of the data that are reported is also discussed.

Based on the review of reporting requirements, the Agency is confident reporting coverage of petroleum refineries and imports captures these sources of petroleum. That is, the volumes reported appear to reflect the totals moving though these sectors and the reporting is at the facility/owner level and is traceable to the facility and owner.

3b.1.Reporting Gaps in Industry Coverage

Refineries and importers report an extensive amount of information on the flows and volumes of their products. They do not, however, report the actual carbon content of their products. They also report volumes of products in fairly aggregated categories, which, in some cases, include fuels with highly variable carbon content. The use of default carbon content factors for these aggregate categories may result in emissions estimates that are not sufficiently precise.

In terms of crude oil it might be possible for each refinery to report the carbon content of the crude oil it uses by separate batch. The EIA forms on crude oil imports contain data on the origin of the crude oil and its API gravity and sulphur content. There are assays available on all major crude oils and part of a full assay is the carbon content of the crude oil. The same is true of domestic crude oil. Some states, particularly California and Texas, have data on the quality of crude oils on a well by well basis. And refineries certainly test each batch they receive since refineries are configured to optimally run within a certain range of quality. However, most refineries use more than one type of crude oil and mingle their crude oil streams presenting an additional problem.

For the past 70 years the National Institute for Petroleum and Energy Research (NIPER) at Bartlesville Research Centre in Oklahoma has conducted sampling surveys of gasoline (winter and summer), aviation fuels, and distillates (on-road diesel, diesel for farm vehicles, railroads and marine engines and heating oil) known as the Petroleum Product Surveys (PPS). These surveys are conducted on a nation wide basis and the results based on laboratory tests conducted at Bartlesville. Gasoline samples are taken at the gas stations in order to catch the additives and biofuels. Carbon is not reported. Distillate samples are taken at refineries and only the carbon residue is reported. The Ramsbottom Carbon Residue Test, ASTM[12] Designation D524, is used.

A petroleum product carbon measurement and monitoring system would require laboratory tests or robust default factors. This is discussed further in Section 4.

3b.2. Data Sensitivity

Much of the data reported to EIA, particularly that reported by refiners, is classified by law as being proprietary. EIA publications report data in the aggregate in a manner that precludes the identification of individual facilities, with the exception of details on the nameplate capacity of the process units and types of process units at each individual refinery. Import data are also reported by importing facility or by corporate entity. In some cases it is possible to arrive at information on individual refiners by examining their web sites and their filings with the SEC. However, this is very variable as some companies reveal a great deal of information, but others do not. Most refiners are very careful to not reveal proprietary secrets that bear on economic performance.

[12] American Society for Testing and Materials

For refiners the core of their business sensitive data consists of data on "runs and yields" and economics. "Runs and yields" refer to individual intermediate stream rates from and between processing units, and through those, the yields of products that they are able to obtain from the crude oils processed. Data on the physical structure of refineries, and often on the specific type of processing technologies, is publicly available as is the type of imported crude oil that each refinery uses. Domestic crude oil use is also often known. However, utilization, which is measured on the first crude oil processing step, the atmospheric distillation tower (ADT), and the yields of the individual products are never available on an individual refinery basis.

Take a case in point: refinery A and refinery B may be using relatively similar crude oils and have similar downstream processing units. The technology used in the ADT and secondary units will likely be different resulting in different production results. Downstream processing units may be the same basic type of technology but the yields may be different depending on the intensity of the processing, the types of catalysts used, the maintenance condition of the equipment and a host of other physical and operating variables, some decided on a day to day basis depending on market and economic factors. In other words refinery A's more efficient equipment, better technical knowledge, and quicker business decision-making may result in substantially higher yields of higher value products, and hence, higher profits than refinery B.

One of the reasons that many refiners subscribe to the Solomon Benchmarking Surveys is that it allows each refinery to rate itself against the best industry practices of its peers in a number of areas ranging from energy efficiency to management practices.

3b.3. Quality Assurance and Control

There is very little information on the quality of data reported on the various forms. There is the presumption that mandatory reports with sanctions for not reporting will be accurate as far as the reporting requirements go. Some of the ambiguities in reporting requirements probably have been worked out between the agencies and the reporting community in the years since these reports have been required.

4.0. Analysis Supporting the Rule

This section discusses default values for the carbon content of refined and semi refined petroleum products, natural gas liquids, and biomass as well as potential methods for direct measurement of carbon content. This is followed by a discussion of the threshold calculations and the cost of the rule.

4.1. Default Carbon Content Factors

4.1.1 Default Petroleum Product Carbon Content Factor Uncertainties

In 1994 the EIA developed new emissions coefficients to replace the coefficients from the IPCC, which were based on samples from Britain. The EIA 1994 published report, *Emissions of Greenhouse Gases in the United States 1987-1992,* cited previous empirical research from 1929 and 1979 that established a set of derived formulas between density, energy content per unit weight and volume, and carbon and hydrogen content. The report compared the emission coefficients calculated on the basis of the derived formulas with actual emissions coefficients of samples from diverse sources of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The actual fuel samples were of a limited number and taken up to 81 years ago. In the absence of more exact information, this empirical relationship has been used by EIA. In addition, the EIA adopted the Bureau of Mines thermal conversion factors published up to 58 years ago.

Below is a review of data sources used in the existing carbon emission coefficients developed by the EIA and used in EPA's annual *U.S. GHG Inventory*.

Motor Gasoline and Motor Gasoline Blending Components

a) The density of motor gasoline is drawn from NIPER's, *Motor Gasolines, Summer* (various years) and NIPER's, *Motor Gasolines, Winter* (various years).

b) The characteristics of reformulated gasoline additives are taken from the American Petroleum Institute, *Alcohols and Ethers: A Technical Assessment of Their Applications as Fuels and Fuel Components*, API 4261.

c) The carbon content of motor gasoline is found in Mark DeLuchi, *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity,* Volume 2, ANL/ESD/TM-22, Vol. 2 (Chicago, IL: Argonne National Laboratory, November 1993), Appendix C, pp. C-1 to C-8 and ultimate analyses of one sample of shale-oil derived gasoline from Applied Systems Corp., *Compilation of Oil Shale Test Results* (Submitted to the Office of Naval Research, April 1976), p. 3-2, three varieties of gasoline from C.C. Ward, "Petroleum and Other liquid Fuels," in *Marks' Standard Handbook for Mechanical Engineers* (New York, NY: McGraw-Hill, 1978), pp. 7-14, and one sample of gasoline from J.W. Rose and J.R. Cooper, *Technical Data on Fuel,* The British National Committee, World Energy Conference, London, England (1977).

d) EIA adopted the Bureau of Mines thermal conversion factor of 5.253 million Btu per barrel for conventional gasoline as published by the Texas Eastern Transmission Corporation in Appendix V of *Competition and Growth in American Energy Markets 1947-1985*, a 1968 release of historical and projected statistics.

e) The factors for reformulated and oxygenated gasolines, both currently 5.150 million Btu per barrel, are based on data published in EPA's, Office of Mobile Sources, National Vehicle and Fuel Emissions Laboratory report EPA 420-F-95-003, *Fuel Economy Impact Analysis of Reformulated Gasoline.*

Jet Fuel

The carbon content of naphtha-based jet fuel is from C.R. Martel and L.C. Angello, "Hydrogen Content as a Measure of the Combustion Performance of Hydrocarbon Fuels," in *Current Research in Petroleum Fuels,* Volume I (New York, NY: MSS Information Company, 1977), p. 116.

The density of naphtha-based jet fuel is from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (Philadelphia, PA, 1985), p. 60

Jet Fuel, Naphtha-Type. EIA adopted the Bureau of Mines thermal conversion factor of 5.355 million Btu per barrel for "Jet Fuel, Military" as published by the Texas Eastern

Transmission Corporation in the report *Competition and Growth in American Energy Markets 1947-1985*, a 1968 release of historical and projected statistics.

Carbon content and density for kerosene-based jet fuels is drawn from O.J. Hadaller and A.M. Momenthy, *The Characteristics of Future Fuels,* Part 1, "Conventional Heat Fuels" (Seattle, WA: Boeing Corp., September 1990), pp. 46-50

Jet Fuel, Kerosene-Type. EIA adopted the Bureau of Mines thermal conversion factor of 5.670 million Btu per barrel for "Jet Fuel, Commercial" as published by the Texas Eastern Transmission Corporation in the report *Competition and Growth in American Energy Markets 1947-1985*, a 1968 release of historical and projected statistics.

Distillate Fuel
Carbon content and density were derived from the following:

a) Four samples of distillate from C. T. Hare and R.L. Bradow, "Characterization of Heavy-Duty Diesel Gaseous and Particulate Emissions, and the Effects of Fuel Composition," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128;

b) Three samples from E.F. Funkenbush, D.G. Leddy, and J.H. Johnson, "The Organization of the Soluble Organic Fraction of Diesel Particulate Matter," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979) p. 128;

c) One sample from R.L. Mason, "Developing Prediction Equations for Fuels and Lubricants," SAE Paper 811218, p.34;

d) One sample from C.T. Hare, K.J. Springer, and R.L. Bradow, "Fuel and Additive Effects on Diesel Particulate- Development and Demonstration of Methodology," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 179; and

e) One Sample from F. Black and L. High, "Methodology for Determining Particulate and Gaseous Diesel Emissions," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

EIA adopted the Bureau of Mines thermal conversion factor of 5.825 million Btu per barrel as reported in a Bureau of Mines internal memorandum, "Bureau of Mines Standard Average Heating Values of Various Fuels, Adopted January 3, 1950." A standard heat content was adopted from EIA, *Annual Energy Review 2000*, Appendix A (Washington, D.C., July 2001).

Residual Fuel
The carbon content of residual fuel oil is based on the following:

a) Three samples of residual fuel from the Middle East and one sample from Texas in F. Mosby, G.B. Hoekstra, T.A. Kleinhenz, and J.M. Sokra, "Pilot Plant Proves Resid Process," in *Chemistry of Petroleum Processing and Extraction* (MSS Information Corporation, 1976), p.227;

b) Three samples of heavy fuel oils from J.P. Longwell, "Interface Between Fuels and Combustion," in *Fossil Fuel Combustion: A Sourcebook* (New York, NY: John Wiley & Sons, 1991);

c) Three samples of heavy fuel oils from C.C. Ward, "Petroleum and Other Liquid Fuels," in *Marks Standard Handbook for Mechanical Engineers* (New York, NY: McGraw-Hill, 1978), pp. 7-14;

d) Two samples of heavy fuel oils from, D.A. Vorum, "Fuel and Synthesis Gases from Gaseous and Liquid Hydrocarbons," in American Gas Association, *Gas Engineer's Handbook* (New York, NY: Industrial Press, 1974), p. 3/71; and

e) One sample of heavy fuel oil from W. Rose and J.R. Cooper, *Technical Data on Fuel,* The British National Committee, World Energy Conference, London, England (1977).

The density of residual fuel consumed for electric power generation was from EIA, *Cost and Quality of Fuels* (Washington, D.C.).
The density of residual fuel consumed in marine vessels was from EIA, Petroleum Supply Division, *Btu Tax on Finished Petroleum Products,* (unpublished manuscript, April 1993) and the National Institute for Petroleum and Energy Research, *Fuel Oil Surveys* (Bartlesville, OK, 1992).
EIA adopted the thermal conversion factor of 6.287 million Btu per barrel as reported in the Bureau of Mines internal memorandum, "Bureau of Mines Standard Average Heating Values of Various Fuels, Adopted January 3, 1950."

Liquefied Petroleum Gases (LPG: ethane, propane, isobutane, and n-butane.)
Carbon share, density and heat content of liquefied petroleum gases were adopted from V.B. Guthrie (ed.), "Characteristics of Compounds", *Petroleum Products Handbook*, (New York, NY: Mcgraw-Hill, 1960), p.3-3.

Aviation Gasoline
Fuel characteristics were taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (Philadelphia, PA, 1985).

EIA adopted the thermal conversion factor of 5.048 million Btu per barrel as adopted by the Bureau of Mines from the Texas Eastern Transmission Corporation publication *Competition and Growth in American Energy Markets 1947-1985*, a 1968 release of historical and projected statistics.

Asphalt
Ultimate analyses of twelve samples of asphalts showed an average carbon content of 83.5 percent.

EIA adopted the thermal conversion factor of 6.636 million British thermal units (Btu) per barrel as estimated by the Bureau of Mines and first published in the *Petroleum Statement, Annual, 1956.*

The density of asphalt is from American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (Philadelphia, PA, 1985).

Lubricants
Ultimate analysis of a single sample of motor oil yielded a carbon content of 85.8 percent.

EIA adopted the thermal conversion factor of 6.065 million Btu per barrel as estimated by the Bureau of Mines and first published in the *Petroleum Statement, Annual, 1956.*

The density of lubricants was adopted from American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (Philadelphia, PA, 1985).

Petrochemical Feedstocks
The carbon content and density of naphthas is estimated based on G.H. Unzelman, "A Sticky Point for Refiners: FCC Gasoline and the Complex Model," *Fuel Reformulation* (July/August 1992), p. 29.

EIA adopted the thermal conversion factor of 5.248 million Btu per barrel, equal to the thermal conversion factor for special naphthas.

Kerosene
The average density of 41.4 degrees API and average carbon share of 86.01 percent was found in five ultimate analyses of No. 1 fuel oil samples

EIA adopted the Bureau of Mines thermal conversion factor of 5.670 million Btu per barrel as reported in a Bureau of Mines internal memorandum, "Bureau of Mines Standard Average Heating Values of Various Fuels, Adopted January 3, 1950."

Petroleum Coke
Carbon content for petroleum coke was estimated from two samples from S. W. Martin, "Petroleum Coke," in Virgil Guthrie (ed.), *Petroleum Processing Handbook* (New York, NY: McGraw-Hill, 1960), pp. 14-15.

Density of petroleum coke adopted from American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (Philadelphia, PA, 1985).

EIA adopted the thermal conversion factor of 6.024 million Btu per barrel as reported in Btu per short ton in the Bureau of Mines internal memorandum, "Bureau of Mines Standard Average Heating Values of Various Fuels, Adopted January 3, 1950." The Bureau of Mines calculated this factor by dividing 30.120 million Btu per short ton, as given in the referenced Bureau of Mines internal memorandum, by 5.0 barrels per short ton, as given in the Bureau of Mines Form 6-1300-M and successor EIA forms.

Special Naphtha
EIA adopted the Bureau of Mines thermal conversion factor of 5.248 million Btu per barrel, which was assumed to be equal to that of the total gasoline (aviation and motor) factor and was first published in the *Petroleum Statement, Annual, 1970.*

Density and aromatic contents for special naphthas are from K. Boldt and B.R. Hall, *Significance of Tests for Petroleum Products* (Philadelphia, PA: American Society for Testing and Materials), p. 30.

Petroleum Waxes
The density of paraffin wax is from American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (Philadelphia, PA, 1985). The density of microcrystalline waxes is based on 10 samples found in V. Guthrie (ed.), *Petroleum Products Handbook* (New York, NY: McGraw-Hill, 1960).

EIA adopted the thermal conversion factor of 5.537 million Btu per barrel as estimated by the Bureau of Mines and first published in the *Petroleum Statement, Annual, 1956*.

Miscellaneous Products
EIA adopted the thermal conversion factor of 5.796 million Btu per barrel as estimated by the Bureau of Mines and first published in the *Petroleum Statement, Annual, 1956*.

The carbon content for crude oil was developed from an equation based on 182 crude oil samples, including 150 samples from U.S. National Research Council, *International Critical Tables of Numerical Data, Physics, Chemistry, and Technology* (New York, NY: McGraw-Hill, 1927).

4.1.2. Petroleum Products

Exhibit 14 shows the full default table provided to reporters in this rule along with footnotes and sources and a brief description of how certain factors were calculated. While many of the emission factors are drawn from EIA data sources described in Section 4.1 of this document, some of them are based on more recent data, and some of them have been calculated specifically for this table.

In the case of transportation fuels containing some portion of biofuels the carbon share in the following table relates only to the fossil fuel components.

Exhibit 14: Calculation of Default Values for all Refined and Semi Refined Petroleum Products.

Refined and Semi-refined Petroleum Products	Column A: Density (API Gravity)	Column B: Specific Gravity	Column C: Density (tonnes/bbl)	Column D: Carbon Share (% of mass)	Column E: Computed Emission Factor (Column C* Column D/100* 44/12 tonnes CO_2/bbl)
Motor Gasoline[1]					
Conventional - Summer[2,3,4]	57.49	0.75	0.12	86.96	0.38
Conventional - Winter[2,3,4]	61.13	0.73	0.12	86.96	0.37
Reformulated - Summer[2,3,5]	58.66	0.74	0.12	86.60	0.37
Reformulated - Winter[2,3,5]	61.49	0.73	0.12	86.60	0.37
Finished Aviation Gasoline[1]	69.00	0.71	0.11	85.00	0.35
Blendstocks					
RBOB[6,1]			0.12	86.60	0.38
CBOB[1]	59.10	0.74	0.12	85.60	0.37
Others[8,9,10]	72.98	0.69	0.11	84.00	0.34
Oxygenates					
Methanol[11,12]	47.39	0.79	0.13	37.50	0.17
GTBA[13,14]	49.91	0.78	0.12	64.90	0.29
t-butanol[15,16,14]	49.91	0.78	0.12	64.90	0.29
MTBE[17]	59.10	0.74	0.12	68.20	0.29
ETBE[17]	59.10	0.74	0.12	70.50	0.30
TAME[17]	52.80	0.77	0.12	70.50	0.31
DIPE[18,19]	63.67	0.73	0.12	70.60	0.30
Kerosene-Type Jet Fuel[1]	42.00	0.82	0.13	86.30	0.41
Naphtha-Type Jet Fuel[1]	49.00	0.78	0.12	85.80	0.39
Kerosene[1]	41.40	0.82	0.13	86.01	0.41
Distillate Fuel Oil					
Diesel No. 1[20,21]	35.50	0.85	0.13	86.40	0.43
Diesel No. 2[22,21]	35.50	0.85	0.13	86.34	0.43
Diesel No. 4[20,21]	23.20	0.91	0.15	86.47	0.46

Fuel Oil No. 1[24]	35.50	0.85	0.13	86.40	0.43
Fuel Oil No. 2[24]	35.50	0.85	0.13	86.34	0.43
Fuel Oil No. 4[24]	23.20	0.91	0.15	86.47	0.46
No. 5 (Navy Special)[25,21]	32.65	0.86	0.14	85.81	0.43
No. 6 (a.k.a. Bunker C)[24]	11.00	0.99	0.16	85.68	0.40
Petrochemical Feedstocks					
Naphthas (< 401°F)[26,1]	61.10	0.73	0.12	84.11	0.36
Other Oils (≥ 401°F)[27,1]	35.50	0.85	0.13	86.34	0.43
Special Naphthas[1]	51.20	0.77	0.12	84.76	0.38
Lubricants[1]	25.60	0.90	0.14	85.80	0.45
Waxes[1]	43.30	0.81	0.13	85.29	0.40
Petroleum Coke[20,1]		0.44	0.07	92.28	0.23
Asphalt and Road Oil[1]	5.60	1.03	0.16	83.47	0.50
Still Gas[28,29]		0.41	0.07	24.40	0.06
Ethane[30,31]	246.84	0.37	0.06	80.00	0.17
Ethylene[32,33]	117.62	0.568	0.09	85.71	0.28
Propane[31]			0.08	81.80	0.24
Propylene[34,35]		0.52	0.08	85.71	0.26
Butane[31]			0.09	82.80	0.28
Butylene[36,37]	71.51	0.70	0.11	85.71	0.35
Isobutane[31]			0.09	82.80	0.27
Isobutylene[38,39]	109.19	0.5879	0.09	85.71	0.29
Pentanes Plus[1]	81.70	0.66	0.11	83.70	0.32
Miscellaneous Products *[1]	30.50	0.87	0.14	85.49	0.43
Unfinished Oils[1]	30.50	0.87	0.14	85.49	0.43
Naphthas[40,21]	56.80	0.75	0.12	85.70	0.37
Kerosenes[40]	41.10	0.82	0.13	85.80	0.41
Heavy Gas Oils[40]	20.90	0.93	0.15	85.80	0.46
Residuum[40,21]	6.90	1.02	0.16	85.70	0.51
Waste Feedstocks**[1]	25.60	0.90	0.14	85.71	0.45

	Conversion Factors			
	SG to lb/gal, multiply by	8.32830		
	g/cm3 to lb/gal, multiply by	8.34568		
	lb/ft.3 to lb/gal, multiply by	7.480522589		

* Includes petrolatum, lube refining byproducts (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuel, synthetic natural gas feedstocks, specialty oils, and any other product not listed above that leaves the refinery.

** Used plastic, used motor oils, used dry cleaning solvents, etc.

[1] From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007. Table 6-5. Data for kero- and naphtha-based jet fuel received by personal communication from EIA on 21 August 2008

[2] Given the sample data (from the Northrop Grumman *Petroleum Product Surveys*) of summer and winter API Gravities for both reformulated and conventional gasoline, a 2 sample t-test was performed to test the null hypothesis that the winter and summer samples came from the same population. The results showed that there is a statistically significant difference between the means of the summer and winter API Gravities, thus, a separate emission factor is calculated for each category.

[3] Dickson, Cheryl. Petroleum Product Study, Northrup Grumman, Gasoline, 2007

[4] Calculated based on the following assumptions:

Conventional gasoline consists of the following components (from sample regular unleaded gasoline - http://www.marathonpetroleum.com/content/documents/mpc/msds/0127MAR019.pdf):

	Weight Percent	Carbon share (weight %), based on molecular formula
Ethanol	0.1	0.52
Aromatics (assumed toluene)	0.29	0.91
Olefins (C_nH_{2n})	0.17	0.86
Saturated Hydrocarbons (C_nH_{2n+2})	0.43	0.845
Benzene	0.01	0.92
Weight Percent Sum, Excluding Ethanol	0.9000	

A weighted average of the carbon share of these compounds (excluding ethanol) was calculated to get the weight percent carbon for conventional gasoline.

Calculation of Carbon Share: Column E = ((0.29/0.9)*0.91 + (0.17/0.9)*0.86 + (0.43/0.9)*0.845 + (0.01/0.9)*0.92

Column E = 0.8696*100

Column E = 86.96

[5] Calculated based on the following assumptions:

Reformulated gasoline consists of the following components (from sample regular unleaded gasoline with EtOH - http://www.marathonpetroleum.com/content/documents/mpc/msds/0130MAR019.pdf):

	Weight Percent	Carbon share (weight %), based on molecular formula
Ethanol	0.0575	0.52
Aromatics (assumed toluene)	0.175	0.91
Olefins (C_nH_{2n})	0.15	0.86
Saturated Hydrocarbons (C_nH_{2n+2})	0.5425	0.845
Benzene	0.075	0.92
Weight Percent Sum, Excluding Ethanol	0.9425	

A weighted average of the carbon share of these compounds, excluding ethanol, was calculated to get the weight percent carbon for reformulated gasoline.

Calculation of Carbon Share:

Column E = (0.175/0.9425)*0.91 + (0.15/0.9425)*0.86 + (0.5425/0.9425)*0.845 + (0.075/0.9425)*0.92

Column E = 0.8660*100

Column E = 86.60

[6] Source: CITGO MSDS http://www.msds.com/index.asp?open=/protected_public/loginsuccessful.asp

At 60°F, avg density = 6.0-6.4 lbs/gal

[8] Assume "Others" = isooctane

[9] Isooctane Specific Gravity from: http://msds.chem.ox.ac.uk/TR/2,2,4-trimethylpentane.html

[10] Carbon content based on molecular formula of isooctane (C_8H_{10}).

[11] Source: http://avogadro.chem.iastate.edu/MSDS/methanol.htm

[12] Carbon content calculated from molecular formula, CH_4O.

[13] Specific gravity from Material Safety Data Sheet: http://www.sciencestuff.com/msds/C1403.html

[14] Carbon content calculated from the molecular formula, $C_4H_{10}O$.

[15] Same compound as GTBA; see footnote 7.

[16] Source (specific gravity): http://msds.chem.ox.ac.uk/BU/tert-butyl_alcohol.html

[17] From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007. Table 6-6.

[18] Source (specific gravity): http://www.coleparmer.com/Catalog/Msds/00803.htm

[19] Carbon content calculated from the molecular formula, $C_6H_{14}O$.

[20] Density from: http://www.engineeringtoolbox.com/fuels-densities-specific-volumes-d_166.html

[21] From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007

http://www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2005).pdf

pg. 185: "If one knows nothing about the composition of a particular petroleum product, assuming that it is 85.7 percent carbon by mass is not an unreasonable first approximation."

Thus, for the products whose carbon content is unknown, Column D is assumed to be 85.7%.

[22] Source: Dickson, Cheryl. Petroleum Product Study, Northrup Grumman, Diesel Fuel Oils, 2007	
	pg. 13, Table 2
	National Average was taken, as the difference between densities was determined to NOT be statistically significant.
[24] Source: Table 27-6	
Perry's Chemical Engineer's Handbook, 1997 ed., pg. 27-10	
[25] Source: Wauquier, J.-P., ed. Petroleum Refining, Crude Oil, Petroleum Products and Process Flowsheets	
	(Editions Technip - Paris, 1995)
	pg.225, Table 5.16
[26] Specific gravity from: Meyers, *Handbook of Petroleum Refining Processes*, 3rd ed., (New York, NY: McGraw Hill, 2004), p. 2.10	
[27] From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007	
http://www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2005).pdf	
	pg. 186: "Petrochemical Feedstocks with [. . .] boiling points [higher than 401 degrees F] are assumed to have the same characteristics as distillate fuel."
[28] Weighted average calculated based on samples of still gas from EIA (From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007	
http://www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2005).pdf	
	Specific Gravity Reference:
	http://www.engineeringtoolbox.com/specific-gravities-gases-d_334.html
[29] Based on Calculation of carbon content of Sample Data, given both the composition of Still gas (Hydrogen, Methane, Ethane and Propane), as well as the weight percent of each component.	
Source:	
From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007	
http://www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2005).pdf	
[30] Source: V.B. Guthrie (ed.), Characteristics of Compounds, Petroleum Products Handbook, (New York, NY: McGraw Hill, 1960), p. 3-3	
[31] Source: From EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. Oct. 2007. Table 6-7. http://www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2005).pdf	
[32] Source (specific gravity): http://www.rmisonline.com/chemicaldatabase/ViewInfo1.aspx?SID=112	
[33] Carbon content calculated from the molecular formula C_2H_4.	
[34] Source: V.B. Guthrie (ed.), *Characteristics of Compounds, Petroleum Products Handbook*, (New York, NY: McGraw Hill, 1960), p. 3-3	
[35] Carbon content calculated from the molecular formula C_3H_6.	
[36] Meyers, *Handbook of Petroleum Refining Processes*, 3rd ed., (New York, NY: McGraw Hill, 2004), p. 1.45	
[37] Carbon content calculated from the molecular formula C_4H_8.	
[38] Source: http://www.siri.org/msds/f2/clc/clcvz.html	
[39] Carbon content calculated from the molecular formula C_4H_8.	
[40] Source: www.marscrude.com/mars_assays/july99/assay99.xls	

	As MARS crude is 31°API, it is representative of the type of crude oil that the average US refinery runs. Thus, the data for MARS crude is taken to be representative for all crude run in the US.

Conventional and Reformulated Gasoline

Using conventional and reformulated gasoline sample data from the Northrop Grumman *Petroleum Product Surveys*, the API gravities of over 1,400 samples of gasoline from across the United States were statistically analyzed for a difference in means. Specifically, a two sample t-test was conducted for summer vs. winter API gravities, summer reformulated vs. winter reformulated gravities and summer conventional vs. winter conventional gravities. The t-test was used to test the null hypothesis that the winter and summer samples came from the same population, which would lead to a negligible difference in means between the two data sets. From these tests, it was determined that there is a statistically significant difference between the API gravities of both summer and winter gasoline, as well as between conventional and reformulated gasoline. This difference in API gravity leads to a difference in calculated emission factors. Thus, for the calculation of emission factors, a different mean API gravity for each subset of finished motor gasoline was used.

The carbon contents of reformulated and conventional gasolines were calculated based on laboratory data from a gasoline sample.. Conventional gasoline consists of the following components[13]:

	Weight Percent	Carbon share (weight %), based on molecular formula
Ethanol	0.1	0.52
Aromatics (assumed toluene)	0.29	0.91
Olefins (C_nH_{2n})	0.17	0.86
Saturated Hydrocarbons (C_nH_{2n+2})	0.43	0.845
Benzene	0.01	0.92

The average carbon content for conventional gasoline was determined by taking a weighted average of the carbon shares of each component, excluding ethanol.

The average composition of reformulated gasoline is assumed to be the following[14]:

	Weight Percent	Carbon share (weight %), based on molecular formula
Ethanol	0.0575	0.52
Aromatics (assumed toluene)	0.175	0.91
Olefins (C_nH_{2n})	0.15	0.86

[13] http://www.marathonpetroleum.com/content/documents/mpc/msds/0127MAR019.pdf
[14] http://www.marathonpetroleum.com/content/documents/mpc/msds/0130MAR019.pdf

Saturated Hydrocarbons (C_nH_{2n+2})	0.5425	0.845
Benzene	0.075	0.92

The average carbon content of reformulated gasoline was determined by taking a weighted average of the carbon shares of each component, excluding ethanol.

The omission of ethanol in the determination of carbon content of both conventional and reformulated gasoline is done to prevent reporters from including in their emissions calculation any emissions from the combustion of a biomass-based feedstock. In this rule, potential emissions from the combustion of biomass-based products are accounted for at the time of feedstock harvest, collection, or disposal, not at the point of fuel combustion. This is a longstanding accounting convention adopted by the IPCC, the UNFCCC, the U.S. GHG Inventory, and many other State and regional GHG reporting programs.

If a refinery produces an ex refinery gate product that has been blended with ethanol, it should follow the specific calculations provided in the regulation to ensure that the potential CO_2 emissions of the petroleum-based portion of the product are not overestimated.

The samples used in the table above contain ethanol because the only publicly available compositions of gasoline were gasoline that included ethanol. Ethanol was omitted from the calculation of total weight percent of gasoline, thus not affecting the final emission factor.

Finished Aviation Gasoline
The average emission factor (EF) for finished aviation gasoline was calculated from the API Gravity and carbon content of finished aviation gasoline, as reported in Table 6-5 of the Energy Information Administration's (EIA) *Documentation for Emissions of Greenhouse Gases in the United States.*

Blendstocks
The physical properties for RBOB (Reformulated Blendstock for Oxygenate Blending), CBOB (Conventional Blendstock for Oxygenate Blending) and GTAB (Gasoline Treated as Blendstock) were taken as equal to the properties of finished motor gasoline, except where noted.

Oxygenates
The chemical properties of each oxygenate were taken from references as noted. The carbon contents were computed from the compounds' molecular formulas.

Kerosene-Type Jet Fuel
The average EF for kerosene-type jet fuel was calculated from the API Gravity and carbon content of kerosene-type jet fuel, as reported in Table 6-5 of the Energy Information Administration's (EIA) *Documentation for Emissions of Greenhouse Gases in the United States.*

Naptha-Type Jet Fuel

The average EF for naptha-type jet fuel was calculated from the API Gravity and carbon content of naptha-type jet fuel, as requested, from background documents to the Energy Information Administration's (EIA) *Documentation for Emissions of Greenhouse Gases in the United States.*

Kerosene
The average EF for finished kerosene was calculated from the API Gravity and carbon content of kerosene, as reported in Table 6-5 of the Energy Information Administration's (EIA) *Documentation for Emissions of Greenhouse Gases in the United States.*

Diesel Fuel Oil No.1 and No.4
The physical and chemical properties of these fuel oils were taken from *Perry's Chemical Engineer's Handbook, 1997 ed.* Diesel fuel oil No.1 and No.4 are considered chemically similar to their fuel oil counterparts.

Diesel Fuel Oil No.2
The national average of API gravity for diesel fuel oil No.2 was taken from the Northrop Grumman *Petroleum Product Survey* for Diesel Fuel Oils. Given the samples of diesel fuel from across the country, a statistical analysis was performed to test whether there was a significant difference between the means of each region. A statistically significant difference was not found, thus, the data could be treated as one set and averaged together for a nation-wide mean API gravity. As with diesel fuel oil Nos. 1 and 4, the average carbon content of No.2 was taken as the average carbon content of all petroleum products, due to the difficulty in characterizing the average composition of diesel fuels.

Fuel Oil Nos. 1, 2, and 4
The physical and chemical properties of these fuel oils were taken from *Perry's Chemical Engineer's Handbook, 1997 ed.*

Residual Fuel Oil No.5 (Navy Special)
The physical and chemical properties for fuel oil No.5 were taken from the reference book, *Petroleum Refining, Crude Oil, Petroleum Products and Process Flowsheets.* The average carbon content of No.5 was taken as 80% of the carbon content of Fuel Oil No.6 and 20% of the carbon content of Fuel Oil No.2.

Residual Fuel Oil No. 6
The physical and chemical properties of fuel oil No.6 was taken from *Perry's Chemical Engineer's Handbook, 1997 ed.*

Petrochemical Feedstocks – Naphthas
The specific gravity of naphthas was taken from *Handbook of Petroleum Refining Processes,* while carbon content is from Table 6-5 of the EIA's *Documentation for Emissions of Greenhouse Gases in the United States.*

Petrochemical Feedstocks – Other Oils
The average emission factor (EF) for other oils was calculated from the API Gravity and the carbon content of distillate fuels, as reported in Table 6-5 of the EIA's *Documentation for Emissions of Greenhouse Gases in the United States.*

Special Naphthas, Lubricants, Waxes, Petroleum Coke, Asphalt and Road Oil, Pentanes Plus and Miscellaneous Products

The average EFs for the above products were calculated from the API Gravity and the carbon content of each product, as reported in Table 6-5 of the EIA's *Documentation for Emissions of Greenhouse Gases in the United States*, unless otherwise noted.

Still Gas

The carbon content of still gas was calculated using a weighted average of samples given in the EIA's *Documentation for Emissions of Greenhouse Gases in the United States*, using the composition of still gas (hydrogen, methane, ethane and propane), as well as the weight percent of each component gas.

Ethane, Ethylene, Propane, Propylene, Butane, Butylene, Isobutane, Isobutylene

The chemical properties of each were taken from references as noted. The carbon contents were computed from the compounds' molecular formulas.

Unfinished Oils

Emission factors for unfinished oils were calculated from the average API gravity of the oil and the average carbon content of petroleum products, as given in the EIA's *Documentation for Emissions of Greenhouse Gases in the United States*. This carbon content factor was used due to the difficulty in characterizing the average composition of unfinished oils.

Naphthas, Kerosenes, Heavy Gas Oils and Residuum

The physical and chemical compositions of the above products were taken from the characterization of MARS crude. As MARS crude is about 31 degrees API gravity, it is representative of the crude oil that the average US refinery runs. Thus, the data for MARS crude is taken to be representative for all crude run in the US.

4.1.3. Natural Gas Liquids

When crude oil is produced together with associated gas, the wet gas is separated at the lease site and then sent to a natural gas processing plant. At this plant the methane is separated out and sent to the natural gas distribution system. The natural gas liquids (NGLs) are sent to various end users: petrochemical plants, refineries, and in the case of pure streams of butane and propane into the market. In the case of refineries the NGLs are often sent as an undifferentiated stream known as bulk NGLs, that is the C2+ stream shown in Exhibit 15 below.

The crude oil, which is sent to refineries, usually still retains NGLs and these are then separated at the refinery and used in various processing steps where they co-mingle with the NGLs obtained from the natural gas processing plant. Refiners attempting to estimate the carbon content of feedstocks and products are faced with identifying the NGLs that come from natural gas processing plants and the NGLs and their derivatives (propane and propylene) that may come from within the refinery and move out of the refinery to petrochemical complexes, and with deciding whether or not the carbon content of the two streams is similar.

In the case of pure streams, such as propane, butane, isobutane the factors in Exhibit 14 can be used. For the heavier products there is some difference and refiners should decide between the factors in Exhibit 14 and Exhibit 15 depending on what stream of

NGLs they are considering. In all cases, if refiners are unable to determine whether a feedstock is NGL- or petroleum-based, they must report it as a petroleum product.

Heavier NGLs

The carbon content of naphtha obtained during petroleum refining differs from natural gasoline, also called "pentane-plus," obtained during natural gas processing. Refinery naphtha and processing plant natural gasoline contain many of the same hydrocarbons (typically C_5 to C_{12}), but the distribution of these molecules differs. Natural gasoline is the heavier fraction of natural gas that is separated from crude oil at the wellhead. The distribution of hydrocarbons in natural gas tails off quickly for heavier molecules such as C_8 and C_9. Thus, the natural gasoline composition tends to be skewed toward the lighter molecules such as pentane and hexane. Naphtha, including "light straight run," is the distillation fraction that condenses at ambient temperature and atmospheric pressure from crude oil distillation, hydrocarbons that boil between roughly 100°F and 400°F. The boiling range of naphtha fractions (whole naphtha, light naphtha, medium naphtha, heavy naphtha) is decided by each refiner based on its downstream operations and economics.

As a comparison, natural gasoline is typically 83.7% carbon by weight, slightly higher than pentane at 83.33%. An equally distributed whole naphtha cut from 95°F to 420°F (boiling range from pentane to dodecane) is estimated to contain 84.2% carbon by weight, slightly lower than dodecane at 84.71% and approximately the same as naphtha reported in this rule. Natural gasoline has lower carbon content because it naturally lies towards the lighter end of the boiling range, whereas refinery naphtha fractions are more evenly distributed over the entirety of boiling range.

Exhibit 15: Emission Factors for Natural Gas Liquids

NGL's Used in Petroleum Refineries	Column A: Density (API Gravity)	Column B: Specific Gravity	Column C: Density (tonnes/bbl)	Column D: Carbon Share (% of mass)	Column E: Computed Emission Factor (Column C* Column D/100* 44/12 tonnes CO_2/bbl)
C2+	158.80	0.51	0.08	81.79	0.24
C4+	99.46	0.62	0.10	83.15	0.30
C5+	81.70	0.66	0.11	83.70	0.32
C6+	70.60	0.70	0.11	84.04	0.34

Definitions:

C2+ (also known as bulk NGLs) means the NGL fraction consisting of hydrocarbon molecules ethane and heavier. The characteristics for this fraction, as reported in Exhibit 15, are derived from the mixture of 31% ethane and 29% propane as reported in Exhibit 14, and 41% C4+. These proportions were determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100°F and pressure of 40 psig.

C4+ means the NGL fraction consisting of hydrocarbon molecules butane and heavier. The characteristics for this fraction, as reported in Exhibit 15, are derived from the mixture of 39% "pentanes plus" and 61% butane as reported in Exhibit 14. These proportions were determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100°F and pressure of 40 psig.

C5+ refers to "pentanes plus", the characteristics of which can be found in Exhibit 14.

C6+ means the NGL fraction consisting of hydrocarbon molecules hexane and heavier. The characteristics for this fraction, as reported in Exhibit 15, are derived from the assumption that "pentane plus", as reported in Exhibit 14, consists of a mixture of 53% C6+ and 47% pentane. These proportions were determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100°F and pressure of 40 psig.

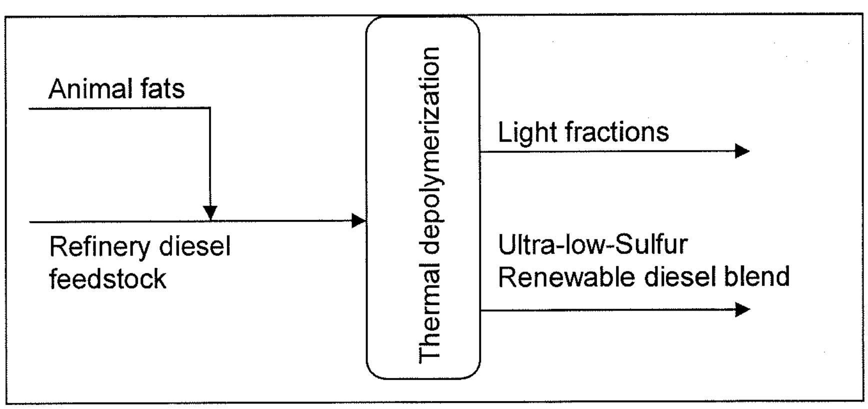
4.1.4. Biomass Feedstock and Products

Refiners that co-process biomass with petroleum feedstock (e.g. renewable diesel) or blend biomass-based fuels into petroleum-based fuels (e.g. ethanol blended with gasoline) must use the biomass emission factors in Table MM-3 in the Rule. This subsection discusses the major types of biofuels and some of the background assumptions for the default carbon content factors in Table MM-3.

Renewable Diesel

Renewable diesel fuel can be made through the co-processing, such as thermal depolymerization, of biological and fossil diesel feedstock. As an example, ConocoPhillips in an alliance with Tyson pioneered an emerging technology that is capable of creating renewable diesel fuel from beef, pork, and poultry fat. This technology uses a thermal depolymerization process to co-process the animal fat with traditional hydrocarbon feedstock. This process is diagrammed in Exhibit 16 below.

Exhibit 16: Renewable Diesel Co-processing By Thermal Depolymerization



The resulting fuel is chemically equivalent to standard diesel fuel produced from purely hydrocarbon feedstocks, meets ASTM standards, and can be transported directly through existing pipelines to distribution terminals. The fuel is approximately equal in energy content to regular diesel, and has a higher cetane value.

The technology was successfully tested at the ConocoPhillips's Whitegate refinery in Cork, Ireland, in 2006[15]. The companies plan to make as much as 175 million gallons per year[16] of renewable diesel to help supplement the U.S.'s diesel supply.

The portion of biological carbon that is present in renewable diesel and light fractions is not readily apparent; therefore the Rule requires that refiners report the carbon content of any biomass that will be co-processed with a petroleum product using default values. Exhibit 18 below shows the estimated default emission factors for both animal fats and vegetable oils that can be co-processed within a refinery. The text following the exhibit lays out the assumptions.

Exhibit 17: Emission Factors for the Bio Portion of Renewable Diesel

Animal Fat and Vegetable Oil as Renewable Diesel Feedstock	Column A: Density (API Gravity)	Column B: Specific Gravity	Column C: Density (tonnes/bbl)	Column D: Carbon Share (% of mass)	Column E: Computed Emission Factor (Column C* Column D/100* 44/12 tonnes CO_2/bbl)
Animal Fat[17]	36.95	0.84[18]	0.13	76.19	0.37
Vegetable Oil[3]	22.64	0.92[19]	0.15	76.77	0.41

Assumptions

Animal fat means fats extracted from animals, with 76.19% carbon by weight, characterized by the composition of fatty acids described in Exhibit 19.

Vegetable oil means oils extracted from vegetation, with 76.77% carbon by weight, characterized by the composition of fatty acids described in Exhibit 19.

[15] ConocoPhillips. *Tyson-COP Alliance.* <http://www.conocophillips.com/Tech/emerging/Tyson/index.htm>.
[16] MSN. *ConocoPhillips, Tyson to make diesel from fats.* April 16, 2007. <http://www.msnbc.msn.com/id/18136194/>.
[17] See Exhibit 19.
[18] Griffin Industries. Material Safety Data Sheet, Identity: Chicken Fat. March 19, 2007. <http://www.griffinind.com/Griffin%2004%20Site/PDFs/MSDS%20sheets/MSDS%20StabilizedChickenFat.pdf>.
[19] Weast, R.C., et al. CRC Handbook of Chemistry and Physics. Boca Raton: CRC Press, 1988-1989: F3. Accessed from <http://hypertextbook.com/facts/2000/IngaDorfman.shtml>.

Exhibit 18: Composition of Animal Fat and Vegetable Oil

Fatty acid	Carbon Share ($\%C_{FA}$)	Animal Fat[20] (X_{FA})	Vegetable oil[21] (X_{FA})
14:0	73.7%	1%	0%
16:0	75.0%	24%	9%
16:1	75.6%	5%	0%
18:0	76.1%	8%	6%
18:1	76.6%	44%	27%
18:2	77.1%	17%	51%
18:3	77.7%	1%	7%

Calculations

Using the assumptions displayed in Exhibit 19, the weight percent of carbon for animal fat and vegetable oil (Column D of Exhibit 18) were calculated using the following equation:

$$\text{Carbon Share} = \sum \left[\%C_{FA} \times X_{FA}\right]$$

Where $\%C_{FA}$ is the weight percent of carbon of a fatty acid and X_{FA} is the composition portion of that fatty acid in animal fat or vegetable oil as shown in Exhibit 19.

Biodiesel/Straight Run Diesel Refinery Blending

Biodiesel is blended into refinery straight run diesel at some petroleum refinery racks. AGE Refining, Inc. was the first petroleum refinery to offer a biodiesel blend to distributors, blended within the refinery gate[22]. A diagram of this blending process is provided in Exhibit 17.

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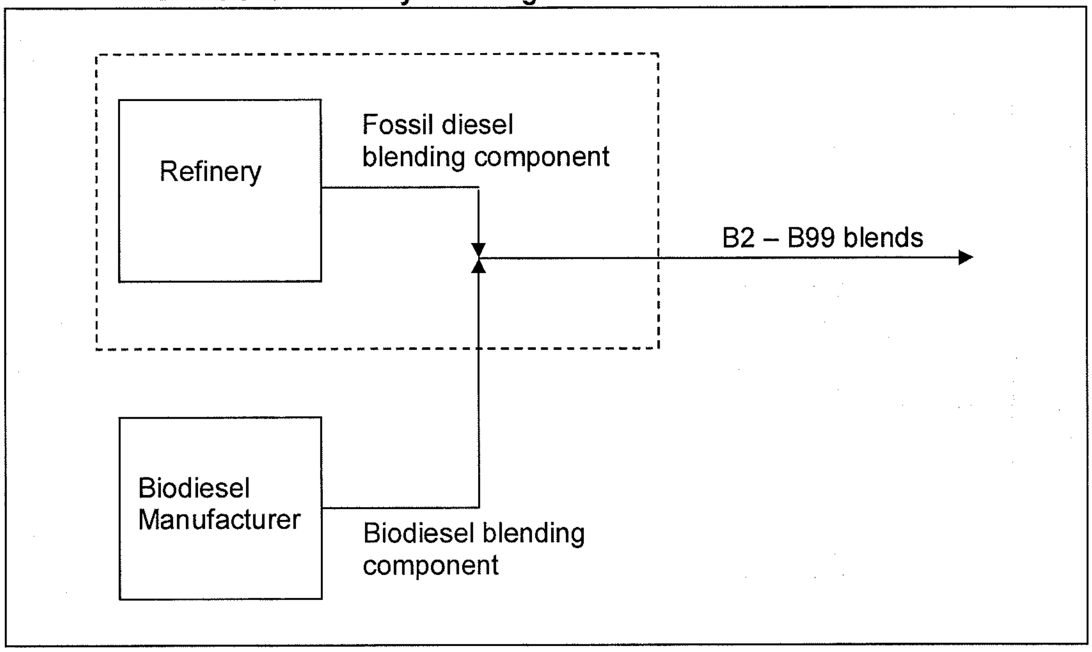
[20] Cyberlipid Center. *Lipids of Land Animals* . Accessed September 9, 2008. <http://www.cyberlipid.org/glycer/glyc0071.htm>. Estimated by Poultry fat.

[21] Erasmus, Udo. *Fats That Heal, Fats That Kill: The Complete Guide to Fats, Oils, Cholesterol, and Human Health.* Table accessed from <http://curezone.com/foods/fatspercent.asp>. Estimated by Soy Bean Oil.

[22] Biodiesel Org. *Texas Oil Refinery Becomes First to Offer Biodiesel Blend in U.S.* May 23, 2005. <http://www.biodiesel.org/resources/pressreleases/pre/20050525_age_refining.pdf>.

Exhibit 19: Refinery Blending of Biodiesel with Fossil Diesel



Blends come in several varieties that are defined by the percentage of biodiesel present in the mixture. B2, B5, B10, B20, B30, B50, B95, B99, and B100 denote diesel fuel blends that are 2%, 5%, 10%, 20%, 30%, 50%, 95%, 99%, and 100% biodiesel respectively.

The 100% biodiesel factor presented in Table MM-3 in the Rule, 0.40 tonnes CO_2/barrel, was derived from Tables IV.A.3-2 and 3-3 in *A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions*.[23]

Ethanol

Ethanol is added to gasoline as an oxygenate. Oxygenates are an affective alternative to aromatics as a gasoline additive to boost octane levels, reduce engine knocking, and to reduce emissions of pollutants in the engine exhaust.

The emissions factor for combustion of ethanol presented in Table MM-3 in the Rule, 0.23 tonnes CO_2/barrel, was derived from Chapter 3 of the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2006*.[24]

[23] EPA420-P-02-001 available at www.epa.gov/otaq/models/analysis/biodsl/p02001.pdf

[24] EPA 430-R-08-005 available at http://epa.gov/climatechange/emissions/downloads/08_CR.pdf

4.2. Direct Measurement Methods for Establishing Carbon Content

4.2.1. Direct Density Measurements

All density measurements of petroleum products can be conducted using appropriate ASTM standard methodologies. The appropriate methods and the products to which each applies are detailed in the paragraphs below.

For liquefied petroleum gases (LPG) and other light hydrocarbons ASTM D1657 – 02(2007) *Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer* can be used. This method covers light hydrocarbons having Reid vapor pressures exceeding 14.696 psia. The prescribed apparatus should not be used for materials having vapor pressure higher than 200 psia at the test temperatur For petroleum products that are low-viscosity, transparent liquids, ASTM D1298 – 99(2005) *Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method* can be used. This method applies to products having Reid vapor pressures less than 14.969 psia. Values are measured on a hydrometer at either the reference temperature or at another convenient temperature. If another temperature is chosen, then readings are corrected to the reference temperature by means of the Petroleum Measurement Tables.

For petroleum products that may not be transparent liquids, but translucent, or more viscous, ASTM D4052 -96(2002)e1 *Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter* can be used. This test method covers petroleum distillates and viscous oils that can be handled in a normal fashion as liquids at test temperatures between 60 and 95 degrees Fahrenheit. Its application is restricted to liquids with vapor pressures below 14.6 psia and viscosities below about 15,000 cSt at the temperature of the test. This test method should not be applied to samples so dark in color that the absence of air bubbles in the sample cell cannot be established with certainty.

For dark, heavy petroleum products, ASTM D5002 – 99(2005) *Standard Test Method for Density and Relative Density of Crude Oils by Digital Analyzer* can be used. This test method covers crude oils and products that can be handled in a normal fashion as liquids at test temperatures between 60 and 95 degrees Fahrenheit. It applies to crude oils and products with high vapor pressures provided appropriate precautions are taken to prevent vapor loss during the transfer of the sample to the density analyzer. Heavier crudes can require measurements at higher temperatures to eliminate air bubbles in the sample.

Petroleum coke requires ASTM D5004 – 89(2004)e1 *Standard Test Method for Real Density of Calcined Petroleum Coke by Xylene Displacement*. This test method is intended for the determination of the real density of calcined petroleum coke, but it is assumed here that it is also suitable for non-calcined petroleum coke. The density is obtained when the particle size of the test specimen is smaller than No. 200 sieve.

For all testing and reporting, specific gravity will be converted density using the value for water at 60 degrees Fahrenheit, 8.32830, as reported from Perry's *Chemical Engineering Handbook* for API gravity of 10 degrees.

4.2.2. Direct Carbon Share Measurements[25]

Carbon content measurement standards are not commonplace. One existing standard is ASTM D5291 (2007) *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.* It was developed mainly for hydrogen and nitrogen but also had the capability to measure carbon, so that was included as well. The measurement method involves placing a sample on an absorbent to minimize vaporization and then combusting a sample at about 1000 degrees Celsius. Combustion products are measured to derive hydrogen, nitrogen, and carbon content.

ASTM D5291(2007) is suitable for heavier hydrocarbon liquids such as kerosenes, diesels, fuel oils, residual oils, lubricants and petroleum coke. Volatile hydrocarbon liquids such as gasoline and other gasoline blend stocks are not recommended for use with the test method: volatile hydrocarbons may escape before the sample reaches the combustion zone, avoiding combustion into carbon dioxide and lowering the carbon share for the measurement. Liquefied petroleum gases (LPG), such as propane and butane, would be entirely unsuitable for this method.

The ASTM committee did not provide specific published methods for determining carbon content of fuels but instead offered that gas chromatography is one possibility. ASTM D6729 – (2004)e1, *Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100 Metre Capillary High Resolution Gas Chromatography* is a recommended alternative. Gas chromatography (GC) would be entirely suitable for LPGs and NGLs as these products have few chemical constituents easily quantified by GC: ethane, ethylene, propane, propylene, and isomers of butane/butylenes, pentane/pentenes and hexane/hexenes. GC would also be suitable for near-pure volatile gasoline blending components such as alcohols and ethers: methanol, n-butyl alcohol, ETBE, TAME, DIPE, and MTBE. GC is a less practical test method for determining carbon share in complex volatile mixtures such as gasoline and gasoline blend-stocks given that it incompletely separates and quantifies the large number of close-boiling point isomers of individual hydrocarbon species. In the absence of a specific standard, ASTM D5291 (2007) may be an appropriate surrogate for determining carbon share in volatile liquid fuels and liquid blending components as long as its limitations are noted, with ASTM D6729 – (2004)el used for LPG products, alcohols and ether blending components.

4.3. Threshold Calculations

4.3.1. Refineries

A threshold analysis was conducted on the petroleum products produced by each refinery to estimate the number of refineries with emissions that surpassed the threshold limits of 1000, 10,000, 25,000 and 100,000 Mt CO_2e per year. For this analysis only those refineries with atmospheric distillation columns were used (140 out of the existing 150 U.S. refineries: EIA 2006). The preliminary threshold analysis was conducted by estimating emissions of the motor gasoline produced by each refinery. United States refineries and their 2006 atmospheric distillation capacities were obtained from the

[25] Information drawn from a memo from ICF to EPA dated July 2008

National Petrochemical and Refiners Association (NPRA) for the threshold analysis. The total motor gasoline produced by PADD district in 2006 was collected from the EIA and was apportioned to each refinery on the basis of their atmospheric distillation capacity (i.e. the ratio of the atmospheric distillation capacity of the refinery to the total capacity of the PADD district was multiplied by the total motor gasoline produced by PADD district to obtain the motor gasoline produced by each refinery). The production numbers obtained from EIA are adjusted for products that are re-processed to convert into other products (i.e. reported numbers are net product volumes). However, products shipped between refineries are not accounted for in the EIA production numbers. Therefore, any product shipped between refineries is double counted in the estimate.

To calculate the CO_2 emissions per refinery, the carbon emission factors (MMTC/10^{15} Btu) for motor gasoline and the various petroleum products (finished aviation gasoline, jet fuel, kerosene, distillate fuel oil, residual fuel oil, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, and miscellaneous products) were obtained from the EIA *Emissions of GHG in the United States 2001,* with the exception of diesel, napthas, and special napthas that were obtained from the API *Compendium of GHG Estimation Methodologies for the Oil and Gas Industry 2004.* The carbon emission factors were converted to CO_2 emission factors by assuming 100% oxidation of the fuels with the exception of petrochemical feedstocks, special napthas, asphalt and road oil, lubricants, and miscellaneous products, which were assumed to have a 40% oxidation rate. The CO_2 emission factors (tonnes CO_2/barrel) were calculated by multiplying the CO_2 emission factor (MMTCO_2/10^{15} Btu) with their corresponding heat content obtained from the EIA *Thermal Conversion Factors 2008.*

An alternative approach to calculating CO_2 emission factors for petrochemical feedstocks, special napthas, asphalt and road oil, lubricants, and miscellaneous products would be to apply to each product a product-specific oxidation factor instead of the 40% average rate.

Exhibit 20: Calculated CO_2 Emission Factor.

Fuel	Heat Content MMBtu/bbl	Emission Factor MMTC/10^{15} BTU	Emission Factor Tonnes CO_2/ bbl (calculated)	Oxidation Rate
Motor Gasoline	5.25	19.34	0.37	100%
Diesel	5.61	0.076*	0.43	100%
Petrochemical Feedstocks	5.69	19.37	0.40	40%
Naphtha/ Reformer Feed	5.25	0.07*	0.38	100%
Kerosene	5.67	19.72	0.41	100%
Kerosene/Jet Fuel	5.67	19.33	0.40	100%
Aviation Gas	5.05	18.87	0.35	100%
Residual Fuel Oil	6.29	21.49	0.50	100%
Distillate	5.83	19.95	0.43	100%
Lubricants	6.07	20.24	0.45	40%
Asphalt and Road Oil	6.64	20.62	0.50	40%
Wax	5.54	19.81	0.40	40%
Miscellaneous Products	5.80	19.81	0.42	40%
Petroleum Coke	6.02	27.85	0.62	100%
Special Naphthas	5.25	0.075*	0.39	100%

*These API values are in tonnes CO_2/MMBtu (average)

The CO_2 emissions from the refineries were obtained by multiplying the volume of motor gasoline produced by each refinery with the CO_2 emission factor (tonnes CO_2/barrel) for motor gasoline. The number of refineries with emissions greater than the specified threshold emission value was identified i.e. for the emission threshold value of 1,000

CO_2, all refineries possessing total emissions >1,000 CO_2 were calculated. The total percent of emissions covered by each threshold limit was calculated by dividing the total emissions covered by the threshold limit with the total national emissions.

All the refineries were found to have emissions greater than the specified thresholds i.e. 1,000, 10,000, 25,000, and 100,000 CO_2 tonnes/year from motor gasoline produced by each refinery alone, and as a result the total emissions from all the petroleum products for the refineries were obtained by multiplying the national production volume for each product with their respective heating values and CO_2 emission factors.

Emissions from LPGs and NGLs were not included in our calculation of the total emissions from all refinery petroleum products. Roughly 75 percent of all LPGs and NGLs in the country in 2006 were used as non-combustion petrochemical feedstocks as indicated by the API report - *2006 Sales of Natural Gas Liquids and Liquefied Refinery Gases.* The API report also indicates that about 46.2 percent of propane was used as combustion fuel, the remaining 53.8 percent being used as petrochemical feedstock, in year 2006. In addition, 9.7 percent of butane and 2.4 percent of ethane were used for combustion purposes in 2006. None of the pentanes were used for combustion use. About 68.6 percent of butane and 67.3 percent of pentanes plus were used as gasoline blendstock in 2006.

An alternative approach to calculating the total emissions from all refinery petroleum products would be to include emissions from NGLs and LPGs. This would be accomplished by multiplying each NGL and LPG product by a product-specific carbon content default value (see Exhibit 24) and by an oxidation factor – either the 40% average or a product-specific factor.

Exhibit 21: Estimated National CO_2 Emissions from Refineries

Net Refinery Production of Finished Petroleum Products	Refinery Net Production (Thousand Barrels per year)	Refinery Net Production (Tonnes CO_2/year)
Finished Motor Gasoline	3,035,705	1,130,618,005
Finished Aviation Gasoline	6570	2,294,294
Kerosene-Type Jet Fuel	540,565	217,197,737
Kerosene	17155	7,031,908
Distillate Fuel Oil	1,477,885	629,610,456
Residual Fuel Oil	231410	114,618,431
Petrochemical Feedstocks	143445	23,187,615

Special Naphthas	13140	5,154,664
Lubricants	66795	12,023,689
Waxes	5475	880,634
Petroleum Coke	309885	190,591,346
Asphalt and Road Oil	184690	37,058,759
Miscellaneous Products	25185	4,240,404

4.3.2. Importers

To conduct a threshold analysis for emissions from petroleum importers, United States petroleum product importers and their respective petroleum product (asphalt, aviation gasoline, butylene, distillate, ethane, ethylene, n-butane, isobutane, jet fuel, kerosene, lubricants, motor gasoline, naphtha, other oils, pentanes plus, petcoke, propane, residual fuel, and special naphtha) and blendstocks (GTAB, RBOB, and others) imports were obtained from the EIA *Company Reports* for the year 2006

To calculate the CO_2 emissions per importer, the carbon emission factors (MMTC/10^{15} Btu) for the petroleum products (asphalt, aviation gasoline, distillate, ethane, n-butane, isobutene, jet fuel, kerosene, lubricants, motor gasoline, other oils, pentanes plus, petcoke, propane, and residual fuel) were obtained from the EIA, *Emissions of GHG in the United States 2001* with the exception of naphthas, and special naphthas that were obtained from the API *Compendium of GHG Estimation Methodologies for the Oil and Gas Industry 2004.* The carbon emission factors for ethylene, and butylene were assumed to be the same as ethane and butane respectively. The blendstocks (GTAB, RBOB, and others) were assumed to have the same carbon emission factor as motor gasoline.

The carbon emission factors were converted to CO_2 emission factors by assuming 100 percent oxidation of the fuels with the exception of petrochemical feedstocks, waxes, asphalt and road oil, and lubricants. Asphalt and road oil, waxes, lubricants, and petrochemical feedstock are reported as NEU (non-energy use) fuels by EPA and emit an average of 40 percent of their carbon as emissions. As a result these fuels were assumed to have 40 percent oxidation rate.The CO_2 emission factors (tonnes CO_2/barrel) were calculated by multiplying the CO_2 emission factor (MMTCO_2/10^{15} Btu) with their corresponding heat content obtained from the EIA, *Thermal Conversion Factors 2008*.

Exhibit 22: Calculated CO_2 Emission Factor.

Fuel	Heat Content	Emission Factor		Oxidation Rate
	MMBtu/bbl	MMTC/10^{15} BTU	Tonnes CO_2/ bbl (calculated)	
Motor Gasoline	5.25	19.34	0.37	100%
Petrochemical Feedstocks	5.69	19.37	0.40	40%
Naphtha/ Reformer Feed	5.25	0.07*	0.38	100%
Ethane	3.08	16.25	0.18	100%
Propane	3.84	17.2	0.24	100%

Fuel	Heat Content	Emission Factor		Oxidation Rate
	MMBtu/bbl	MMTC/10^{15} BTU	Tonnes CO_2/ bbl (calculated)	
Butane	4.33	17.75	0.28	100%
Iso-butane**	3.97	.065*	0.26	100%
Butylene	4.33	17.75	0.28	100%
Ethylene	3.08	16.25	0.18	100%
Pentane Plus	4.62	21.49	0.33	100%
Kerosene	5.67	19.72	0.41	100%
Kerosene/Jet Fuel	5.67	19.33	0.40	100%
Aviation Gas	5.05	18.87	0.35	100%
Residual Fuel Oil	6.29	21.49	0.50	100%
Distillate	5.83	19.95	0.43	100%
Lubricants	6.07	20.24	0.45	40%
Asphalt and Road Oil	6.64	20.62	0.50	40%
Wax	5.54	19.81	0.40	40%
Petroleum Coke	6.02	27.85	0.62	100%
Special Naphthas	5.25	0.075*	0.39	100%

*These API values are in tonnes CO_2/MMBtu (average)
**Isobutane CO_2 emission factor is obtained from form EIA-1605, *Fuel Emission Factors*, Appendix H

The CO_2 emissions per importer were estimated by multiplying the volume of petroleum products and blendstock imported with the corresponding CO2 emission factor (tonnes CO_2/barrel).

Exhibit 23: Calculated CO_2 (tonnes/year) Emissions per Importer

Importers	Total Emissions (tonnes CO_2/year)
AEROPRES CORP	55,446
AFTON CHEMICAL CORP	9,540
AGGREGATE INDUSTRIES	64,200
AGRI-MARK INC	11,500
ALBINA ASPHALT	65,400
ALEUT ENTERPRISE LLC	93,850
ALL STATES ASPHALT INC	54,400
ALON USA LP	16,600
ALPAC MARKETING SERV	8,190
AMERICAN AGIP CO INC	513,990
AMERICAN HYDROTECH INC	9,400
AMERICAN REFINING GROUP	5,940
AMERICHEM SALES CORP	2,070
AMERIGAS PROPANE INC	43,055
AMMEX INC	163,940
ANDERES OIL INC	5,160
APEX OIL CO INC	372,680
ASTRA OIL CO LLC	1,418,390

Importers	Total Emissions (tonnes CO_2/year)
ATLANTIC ENERGY INC	321,700
ATLANTIC TRADING MARKETING	1,635,320
AUTORE OIL CO	12,470
AVFUEL CORP	7,370
AXMEN PROPANE INC	9,191
BARR BROTHERS INC	860
BETTER ROAD ASPHALT CORP	105,800
BHREAC PETROLEUM INC	58,800
BIRCHWOOD TRADING INC	25,000
BITUMAR	282,600
BLUE SEAL FEEDS INC	3,000
BLUE WATER OIL TRANSPORT	92,640
BOGNAR EJ INC	52,700
BOMINFLOT ATLANTIC LLC	582,000
BP CANADA ENERGY MKTG CORP	3,273,172
BP PRODUCTS N AMERICA INC	33,648,580
BP WEST COAST PRODUCTS LLC	100,400
BULK TRADING & TRANSP CO	17,000
BURLINGTON NORTHERN RR	361,200
B-V ASSOC INC	2,160
CAPEX INDUSTRIAL LTD	2,337,400
CARBON PRCSG RECLAMATION LLC	207,500
CARGILL INC	246,050
CARIBBEAN PETROLEUM	1,359,220
CASS CITY OIL & GAS CO	55,470
CASTROL N AMER AUTOMOTIVE INC	34,380
CAVALIER GAS CO	484
CENTENNIAL ENERGY LLC	258,736
CENTER OIL CO	181,890
CHEMOIL CORP	6,731,500
CHEVRON PHILLIPS CHEM PR CORE	28,080
CHEVRON PUERTO RICO LLC	22,200
CHEVRON USA INC	8,927,056
CHS INC	113,502
CII CARBON LLC	742,140
CIRCLE LUBRICANTS INC	3,780
CITGO ASPHALT REFINING CO	1,339,800
CITGO PETROLEUM CORP	20,899,760
CITY SERVICE VALCON	388,825
CLARK OIL TRADING CO	92,880
COCHIN PL LTD	2,275,847
COLEMAN OIL CO	46,220
COLONIAL OIL INDUSTRIES INC	20,387,430

Importers	Total Emissions (tonnes CO_2/year)
CONOCOPHILLIPS CO	15,310,698
CONSUMERS ENERGY CO	69,000
CONTINENTAL MATERIALS INC	16,000
D & C TRANSPORTATION INC	7,498
DAIGLE OIL CO	2,580
DEAD RIVER CO	82,481
DELTA WESTERN INC	335,300
DOMTAR INDUSTRIES INC	131,000
DOW CHEMICALS CO THE	648,759
DOW HYDROCARBONS & RESRCS INC	6,796,160
EASTERN AVIATION FUELS INC	14,250
EASTERN ENVIRONMENTAL SERVICES	3,420
EMERALD KALAMA CHEMICAL LLC	162,640
ENTERPRISE CO INC	7,926,859
EQIUSTAR CHEMICALS LP	4,876,160
EQUITABLE OIL PURCHASING	83,420
EXXONMOBIL CHEMICAL	419,840
EXXONMOBIL OIL CORP	8,213,980
FARSTAD OIL INC	53,992
FERRELL NORTH AMERICA	37,975
FLINT HILLS RESOURCES LP	483,600
FORMOSA PLASTICS CORP USA	2,200,580
FUEL & MARINE MARKETING LLC	1,666,500
GAS CO THE	32,412
GAS SUPPLY RESOURCES INC	456,669
GAS SUPPLY RESOURCES LLC	581,721
GEORGIA PACIFIC CORP	678,280
GETTY PETROLEUM MARKETING INC	162,060
GIANT YORKTOWN INC	233,470
GLENCORE LTD	12,684,180
GLOBAL CO LLC	4,186,980
GOETZ ENERGY	112,010
GREAT LAKES CARBON LLC	2,379,560
GRIFFITH ENERGY DBA SEIMAX	163,994
GRIFFITH OIL CO INC	80,520
GULF OIL LP	50,310
HARBOR BUNKERING CORP	457,830
HAWAII FUELING FACILITIES CORP	928,800
HELM US CHEMICAL CORP	27,690
HERMAN OIL INC	27,090
HESS CORP	30,483,590
HOVENSA LLC	1,491,760
HUDSON LIQ ASPHALT INC	83,800

Importers	Total Emissions (tonnes CO_2/year)
ICC CHEMICAL CORP	69,420
IDAHO ASPHALT SUPPLY INC	59,600
IDEMITSU LUBR AMERICA CORP	40,500
INERGY PROPANE LLC	49,343
INFINEUM USA LP	22,500
INTALCO ALUM CORP	112,220
IPC USA INC	810,780
IRVING OIL CORP	24,809,541
IRVING OIL TRANSPORTATION CO	325,600
ISLAND COUNTY PUBLIC WORKS	1,000
ISO BUNKERS LLC	6,500
JACKSON ENERGY AUTHORITY	2,310,740
JARON CORP	13,000
JENSEN NORMAN G INC	131,585
JET GAS INC	2,661
KATAHDIN PAPER CO LLC	217,500
KILDAIR SERVICE LTEE	327,000
KINETIC RESOURCES USA	120,214
KOCH SUPPLY & TRADING CO	1,761,940
KOLMAR AMERICAS INC	598,630
LAKES GAS CO	2,661
LANE CONSTR CORP	12,000
LAXFUEL CORP	5,650,800
LIQUID GAS CO	2,419
LOUIS DREYFUS ENERGY SVCS LP	548,510
LUKOIL PAN-AMERICAS LLC	5,494,000
LUND OIL INC	14,835
MAGRABAR CHEMICAL CORP	540
MAINE PROPANE DSTR	29,267
MARATHON PETROLEUM CO LLC	4,244,131
MATCON TRADING CORP	31,000
MCCAIN FOODS	11,000
MICHIGAN PETROLEUM TECH	71,810
MIDLAND ASPHALT INC	1,200
MIECO INC	244,750
MOORE OIL INC	2,150
MORGAN STANLEY CAPITAL GRP INC	15,481,090
MOTIVA ENTERPRISES LLC	50,000
MX PETROLEUM CORP	98,040
NECO DSTR	274,250
NESTE OIL USA LLC	0
NEXT PETROLEUM LTD	115,950
NOBLE AMERICAS CORP	494,280
NOCO ENERGY CORP	150,913

Importers	Total Emissions (tonnes CO_2/year)
NORTHERN ENERGY INC	161,576
NORTHLAND PRODUCTS CO	1,980
NORTHVILLE INDUSTRIES CORP	1,917,050
NORTHWEST PETROLEUM CO	67,940
NOVA CHEMICAL CORP	832,304
NRG ENERGY MARKETING	251,500
NYNAS USA INC	56,880
OWENS CORNING	27,000
PARAMOUNT PETOLEUM CORP	59,800
PARAMOUNT PETROLEUM CORP	12,400
PARKERS PROPANE GAS CO	89,737
PECKHAM INDUSTRIES INC	66,200
PENNZOIL QUAKER STATE CO	66,600
PETROBRAS AMERICA INC	3,393,370
PETRO-CANADA CHEMICAL INC	367,380
PETROLEUM DIAMOND INC	144,710
PETROLEUM MARINE SERVICE	161,690
PETROSOL INTL	69,419
PHILLIPS C OIL CO	65,360
PIKE INDUSTRIAL INC	40,600
PLAINS MARKETING LP	377,625
PMI TRADING LTD	3,860,990
PONDEROSA PETROLEUM CO	17,500
PRSI TRADING LP	113,590
QUADRA ENERGY TRADING INC	88,528
RECOCHEM INC	12,720
RICH ENERGY INC	4,838
RIO ENERGY INTL	95,500
SABIC MARKETING AMERICAS INC	292,780
SAFETY-KLEEN CANADA INC	85,860
SALMON RESOURCES LTD	114,097
SAMSUNG AMERICA INC	202,540
SARGEANT MARINE INC	68,800
SEA 3 INC	950,829
SEA 3 OF FLORIDA INC	714,029
SEMMATERIALS	107,400
SEMPRA ENERGY TRADING CORP	1,388,000
SEMSTREAM LP	625,017
SENECA PETROLEUM CO INC	27,000
SHELL CO PUERTO RICO LTD	5,000
SHELL GUAM INC	2,263,100
SHELL OIL PRODUCTS US PUGET SOUND	16,000
SHELL US TRADING CO	7,406,470
SIMONS PETROLEUM INC	430
SK E & P CO	256,860

Importers	Total Emissions (tonnes CO_2/year)
SONNEBORN INC	5,400
SPRAGUE ENERGY CORP	526,640
STATOIL MKTG & TRDG US INC	4,099,970
SUBURBAN PROPANE GAS CO	52,246
SUIT-KOTE CORP	25,000
SUNOCO INC	1,426,041
SWANSTON EQUIPMENT CO	16,800
TARGA MIDSTREAM SERVICES LP	2,622,810
TAUBER OIL CO	104,520
TAUBER PETROCHEMICAL CO	68,780
TESORO HAWAII CORP	135,590
TESORO PETROLEUM CORP	1,838,570
TEXAS PETROCHEMICALS LP	877,715
TEXPAR ENERGY LLC	393,680
TIDAL ENERGY MARKETING INC	163,606
TRAFIGURA AG	9,652,636
TRAMMOCHEM DIV OF TRANSAMMONIA INC	131,430
TRANSMONTAIGNE PRODT SVCS INC	312,500
TRIGEANT LTD	52,000
TRIPLE CLEAN OIL CO	39,500
ULTRAMAR ENERGY INC	2,339,570
UPS SUPPLY SERVICES	75,225
VALERO MARKETING & SUPPLY CO	990,250
VITOL SA INC	31,932,359
WARNER PETROLEUM CORP	257,500
WARREN GE	14,725,500
WESTERN PETROLEUM CO	725,090
WESTPORT PETROLEUM INC	6,588,360
WHATCOM BUILDERS INC	5,400
WHITE MOUNTAIN OIL CO INC	2,419
WILLIAMS OLEFINS LLC	171,009

The number of importers with emissions greater than the specified threshold emission value was identified i.e. for the emission threshold value of 1,000 CO_2, and all importers possessing total emissions >1000 CO_2 were calculated. The total percent of emissions covered by each threshold limit was calculated by dividing the total emissions covered by the threshold limit with the total national emissions.

Exhibit 24: Threshold Analysis for Importers

Threshold (tonnes CO_2/year)	1000	10,000	25,000	100,000
Emissions covered (tonnes CO_2/year)	387,150,951	387,029,025	386,720,250	383,492,083

Percentage of Emissions covered	100%	100%	99.89%	99.05%
Importers covered	218	192	173	119
Percentage of importers covered	97%	86%	77%	53%

4.3.3. Exporters

According to the Rule both importers and exporters are to report volumes and emissions at the company level. Import data is available on the EIA website. However, the individual forms that have to be submitted by Exporters to the Department of Commerce are only available for analysis under the FOIA. Consequently, no threshold analysis was performed for Exporters.

4.4. Monitoring Method Costs

Monitoring costs were estimated for each refinery to perform the tests with their in-house laboratories. Test methods for analyzing the carbon content of petroleum products include ASTM D5291 (2007), ASTM D6730-01(2006)e1 and ASTM D6733-01(2006). Alternatively refineries and importers can send the samples to an external lab for testing, the cost of which will be dependant upon specific contract terms unique to each company.

Exhibit 25: Refinery Monitoring and Reporting Costs

Respondent Activity	Respondent Activity Description	Annualized Capital Cost (2006$)			Operating & Maintenance Costs (includes fixed and variable) -- 2006$ (See O&M Tab)			Total Reporting Unit/ Facility Cost (Labor + Capital + O&M)-- 2006$		
		First Year		Second Year	First Year		Second Year	First Year		Second Year
		First Reporting Period - First Year	Subsequent Reporting Period - First Year	Subsequent Reporting Period - Second Year	First Reporting Period - First Year	Subsequent Reporting Period - First Year	Subsequent Reporting Period - Second Year	First Reporting Period - First Year	Subsequent Reporting Period - First Year	Subsequent Reporting Period - Second Year
Registration	Review of regulation requirements, required data and reporting process - (gap analysis)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,235	$ 563	$ 664
	Advice from legal counsel and/ or outside consultants	$ -	$ -	$ -	$ -	$ -	$ -	$ 825	$ 261	$ 261
	Register with EPA; provide facility details, operation parameters, etc.	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,263	$ 231	$ 332
Monitoring	Identify the method and frequency for monitoring each input and output	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,885	$ 462	$ 373
	Monitoring OPTION 1: Use existing data from other reporting requirements or internal company practices (ex. EIA, FERC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Monitoring OPTION 2: Fuel quantity measurement and composition analysis from in-house labs	$ 7,119	$ 21,357	$ 28,476	$ 12,500	$ 37,500	$ 50,000	$ 23,373	$ 59,533	$ 78,706
	Monitoring OPTION 3: Fuel quantity measurement and third party composition analysis	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reporting	Data documentation and report submission	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,694	$ 535	$ 160
Archiving	Time required to file data (hard copy and electronic)	$ -	$ -	$ -	$ -	$ -	$ -	$ 373	$ 373	$ 373
Auditing	Auditing assistance to EPA audit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 842

Exhibit 26: Refinery Unit Cost for Monitoring and Reporting

Monitoring Option or Fuels Calculation Method	Cost of Monitoring Instruments				Monitoring Costs ($/year)		Other Annual Costs - (registration, reporting, archiving, and auditing $/year)		Total Annual Unit Cost - Average ($/year)
	Capital Cost ($)	Equipment Lifetime (years)	Annualized Capital Cost ($/year)	O&M Costs ($/year)	First Year	Second Year	First Year	Second Year	
Option 2	$ 200,000	10	$28,476	$50,000	$89,253	$ 79,079	$12,351	$2,631	$ 91,658

Appendix

Source-specific Summary

Reporting Program/Guidance	Source Category (or Fuel)	Coverage (Gases or Fuels)	Coverage (Emissions Types)	Coverage (Threshold)	Level of Reporting (e.g., facility, unit)	Points of Monitoring	Monitoring Methods for Source/Fuel	Purpose of Method (e.g, mandatory reporting, voluntary reporting, etc)	Supplemental Data Reported (e.g., production, capacity, waste-in-place)	Quality Assurance/Quality Control Procedures
EIA reporting for Refineries	Petroleum Refineries	Petroleum	N/A	Varied	Refinery	Throughout refinery	Meters	Mandatory Reporting	N/A	800, 810, 820 data reconciled against one another for consistency
EPA reporting for Refineries	Petroleum Refineries	Petroleum	NOx, VOC	No threshold	Refinery	Throughout refinery	Meters	Mandatory Reporting	N/A	Internal and random in-person auditing
EIA reporting for Imports	Petroleum Imports	Petroleum	N/A	Varied	Importer	Pipeline - at border Marine - at offload	Meters	Mandatory Reporting	N/A	Weekly and monthly data reconciled against each other for consistency
EPA reporting for Imports	Petroleum Imports	Petroleum	NOx, VOC	No threshold	Importer	Pipeline - at border Marine - at offload	Meters	Mandatory Reporting	N/A	Internal and random in-person auditing
FERC reporting for Exports	Petroleum Exports	Petroleum	N/A	Based on revenue	Pipeline	At border	Meters	Mandatory Reporting	N/A	None currently
MMS reporting for Upstream Production	Petroleum Others	Petroleum	N/A	No threshold	Federal land lessee	Lease meter	Meters	Mandatory Reporting	N/A	Royalty information from OGOR and PASR compared
FHWA reporting for Consumption	Petroleum Others	Petroleum	N/A	N/A	State agency responsible for collection of motor fuel tax	Pump sales	Meters	Mandatory Reporting	N/A	None
Army Corps of Engineers reporting for Marine Movements	Petroleum Others	Petroleum	N/A	Trips less than 1 mile not required to be reported	Domestic commercial operator	Ports	Meters	Mandatory Reporting	N/A	Reconciliation with dock receipts
Oil & Gas Journal Worldwide Refinery Survey	Petroleum Refineries	Petroleum	N/A		Refinery					None

Petroleum Refineries

Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Energy Information Administration	EIA-800 Weekly Refinery and Fractionator Report	Operators of all petroleum refineries and fractionators selected by the EIA	90% (per weekly sample selection procedure)	Input, production, stocks (1000 bbl)	Refinery; Stocks in *custody* of refinery reported regardless of ownership	Quantities of at least 500 barrels are reported	Weekly	Operating information	Yes	No	800, 810 and 820 reconciled against one another for consistency	Report does not contain information on carbon content of fuel
Energy Information Administration	EIA-810 Monthly Refinery Report	Operators of all operating and idle petroleum refineries located in the 50 States, District of Columbia, Puerto Rico, the Virgin Islands, Guam, and other U.S. possessions	All	Refinery input (1000 bbl), Operable capacity of atmospheric crude oil distillation units on the first day of the month (barrels per calendar day), Weighted average sulfur content of crude oil, Weighted average API gravity of crude oil, Refinery operations: beginning stocks, receipts, inputs, production, shipments, fuel uses & losses, ending stocks reported for each product except where field is shaded	Refinery; Stocks in *custody* of refinery reported regardless of ownership	Quantities of at least 500 barrels are reported	Monthly	Operating information	Yes	No	800, 810 and 820 reconciled against one another for consistency	Report does not contain information on carbon content of fuel
Energy Information Administration	EIA-820 Annual Refinery Report	All operating and idle petroleum refineries (including new refineries under construction) and refineries shutdown during the previous year, located in the 50 States, the District of Columbia, Puerto Rico, the Virgin Islands, Guam, and other U.S. possessions	All	Quantity of natural gas and coal purchased for used as a fuel; Quantity of electricity and steam purchased for all uses; Receipts of crude oil (domestic and foreign) by method of transportation; Operable capacity of atmospheric crude oil distillation units on the first day of the year (barrels per calendar day and barrels per stream day), Downstream charge capacity; Production capacity (barrels per stream day); Storage capacity (1000 bbl)	Refinery	None	Annual	Operating information	Yes	Operable atmospheric crude oil distillation capacity available by refinery; Other aggregated data (by PADD and state) available: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html	800, 810 and 820 reconciled against one another for consistency	Report does not contain information on carbon content of fuel

Petroleum Refineries (continued)

Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Energy Information Administration	EIA-819 Monthly Oxygenate Report	Operators of all facilities that produce (manufacture or distill) oxygenates (including MTBE plants, petrochemical plants, and refineries that produce oxygenates as part of their operations located in the 50 States and the District of Columbia	All	Production and stocks of oxygenate products (1000 bbl)	Stocks in *custody* of refinery reported regardless of ownership	500 barrels	Monthly	Operating information	Yes	No	None	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form 3520-20H Anti-Dumping Program Annual Report	Producers and importers of reformulated gasoline (or RBOB), conventional gasoline, or applicable blendstocks	All	Company ID, Facilities represented, Total volume of conventional gasoline produced or imported (gallons)	Refiner / Importer	None	Annual	Operating information	Gasoline volume: yes; Compliance calculations: no	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form 3520-20L Reformulated Gasoline Program NOx Emissions Performance Averaging Report	Producers and importers of reformulated gasoline or RBOB	All	Company ID, Facility ID, Total volume of averaged reformulated gasoline or RBOB (gallons)	Refiner / Importer	None	Annual	Operating information	Gasoline volume: yes; Compliance calculations: no	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form 3520-20M Reformulated Gasoline Program VOC Emissions Performance Averaging Report	Producers and importers of reformulated gasoline or RBOB	All	Company ID, Facility ID, Total volume of averaged reformulated gasoline or RBOB (gallons)	Refiner / Importer	None	Annual	Operating information	Gasoline volume: yes; Compliance calculations: no	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel

Petroleum Refineries (continued)

Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Environmental Protection Agency	EPA Form DSF0600 Designate & Track Total Volume Report	Facilities handling diesel fuel including refiners and importers	All	Company ID, Facility ID, Tax/dye/marker status, Product type, Received (gallon), Delivered (gallon), Produced (gallon), Imported (gallon), Beginning inventory (gallon), Ending inventory (gallon)	Fuel in custody of facility reported regardless of ownership	None	Annual (Quarterly for truck loading terminals)	Operating information	Yes	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Oil & Gas Journal	Worldwide Refinery Survey http://ogjresearch.stores.yahoo.net/worrefsurlat.html			Country; Location; City; State; Number of plants; Crude capacities; Charge capacity for vacuum dist.; Thermal operations; Catalytic reforming, hydrocracking, hydrorefining, hydrotreating, and cracking; Production capacity for alkylation; Polymerization; Aromatics; Isomerization; Lubes; Oxygenates; Asphalt; Hydrogen; Coke; Sulfur			Annual				None	

Petroleum Imports

Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Energy Information Administration	EIA-814 Monthly Imports Report Company level imports data available here: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/company_level_imports/cli.html	All importers of record who import crude or petroleum products into the 50 States and D.C. from foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions	Nearly all (transactions of major products rarely have volumes below reporting threshold)	Importer information, Type of commodity, Port of entry, Country of origin, Quantity (1000 bbl), Sulfur percent by weight API gravity (crude only), Name and location of processing company (crude and unfinished products)	Importer of record	All transactions of at least 500 barrels are reported	Monthly	From foreign supplier	Yes	Yes	Frame check against Customs Form 7501, try to match companies that are not in EIA data	Report does not contain information on carbon content of fuel
Energy Information Administration	EIA-804 Weekly Imports Report	Selected importers of record who import crude or petroleum products into the 50 States and D.C. from foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions; Companies selected into weekly sample must report each week even if there were zero imports	90% (per weekly sample selection procedure)	Importer information, Imports volume by destination (entry port) PADD, Total crude oil imports by country of origin	Importer of record	None	Weekly	Transaction-specific information	Firms have raw information but may not compute these specific numbers without the reporting requirement	No	Imported volumes verified by EIA-814	Report does not contain information on carbon content of fuel
Energy Information Administration	EIA-856 Monthly Foreign Crude Oil Acquisition Report	All firms reporting as of June 1982 and all firms that imported more than 500,000 bbl of foreign crude for the report month	~90% (don't know how much is "under the radar")	Importer information, Country of origin, API gravity, Port of loading, Port of destination, Vessel or pipeline, Terms and location of acquisition, Volume (bbl), Price ($/bbl), Landed cost ($/bbl), Name of vendor	Importer	500,000 barrels of foreign crude acquired	Monthly	At loading; transaction-specific information	Yes	Aggregated data	Imported volumes verified by EIA-814	Carbon content could be derived from raw data reported on crude imports and crude oil assay data
Energy Information Administration	EIA-14 Refiners' Monthly Cost Report	All refiners (except independent natural gas processors)	All	Refiner information, Imported crude cost ($1000), Imported crude volume (1000 bbl)	Refiner	None	Monthly	Summary information	Firms have raw information but may not compute these specific numbers without the reporting requirement	Aggregated data	Imported volumes verified by EIA-814	Report does not contain information on carbon content of fuel

Petroleum Imports (continued)

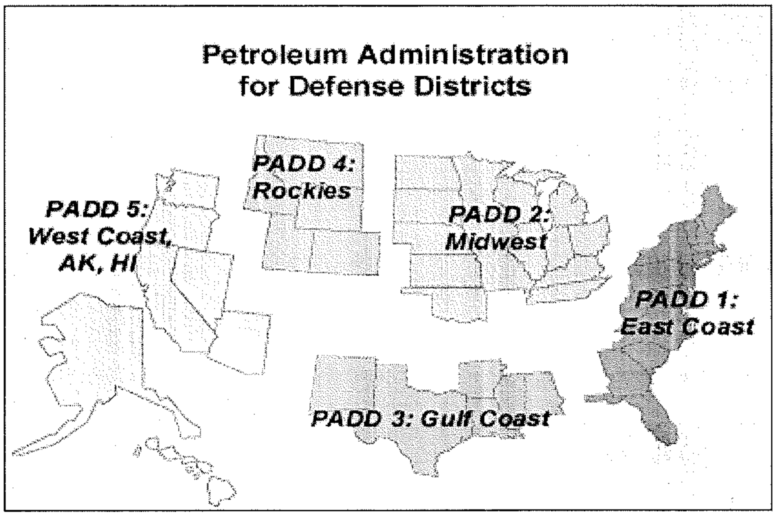
Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Environmental Protection Agency	EPA Form 3520-27 Load Port/Port of Entry Independent Sampling, Testing and Refinery/Importer Identification Form	Importers of gasoline	All	Foreign refinery registration number, Importer registration number and information, Vessel information, Gasoline volume (gallons)	Importer	None	Per shipment	Operating information	Yes	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form 3520-20H Anti-Dumping Program Annual Report	Producers and importers of reformulated gasoline (or RBOB), conventional gasoline, or applicable blendstocks	All	Company ID, Facilities represented, Total volume of conventional gasoline produced or imported (gallons)	Refiner / Importer	None	Annual	Operating information	Gasoline volume: yes; Compliance calculations: no	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form 3520-20L Reformulated Gasoline Program NOx Emissions Performance Averaging Report	Producers and importers of reformulated gasoline or RBOB	All	Company ID, Facility ID, Total volume of averaged reformulated gasoline or RBOB (gallons)	Refiner / Importer	None	Annual	Operating information	Gasoline volume: yes; Compliance calculations: no	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form 3520-20M Reformulated Gasoline Program VOC Emissions Performance Averaging Report	Producers and importers of reformulated gasoline or RBOB	All	Company ID, Facility ID, Total volume of averaged reformulated gasoline or RBOB (gallons)	Refiner / Importer	None	Annual	Operating information	Gasoline volume: yes; Compliance calculations: no	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel
Environmental Protection Agency	EPA Form DSF0600 Designate & Track Total Volume Report	Facilities including refiners and importers of diesel fuel	All	Company ID, Facility ID, Tax/dye/marker status, Product type, Received (gallon), Delivered (gallon), Produced (gallon), Imported (gallon), Beginning inventory (gallon), Ending inventory (gallon)	Fuel in custody of facility reported regardless of ownership	None	Annual (Quarterly for truck loading terminals)	Operating information	Yes	No	Sanctions for failure to comply; internal auditing for completeness and accuracy of submitted data; random in-person audit by EPA's enforcement office	Report does not contain information on carbon content of fuel

Petroleum Exports

Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Department of Commerce	Commerce Form 7525-V Shipper's Export Declaration	Generally required for shipment from the U.S. and U.S. possessions to foreign countries	All	Quantity (bbl), Weight (kg)	N/A	N/A	Per shipment	Transaction-specific information	Yes, operating information	Aggregated export statistics available from Census Bureau (EM-522, EM-594)	Unknown	Report does not contain information on carbon content of fuel

Petroleum Others

Agency	Reporting Form Full Official Title	Who must file the report?	What percent of facilities and fuel flow does the report capture? (i.e., what is the coverage of the industry?)	What is Reported (product and units?)	How is ownership of the fuel throughput treated in the report form?	What is the threshold for reporting, i.e., minimum level of throughput or facility size?	What is the frequency of Reporting?	How does the facility collect the data reported?	Would the facility need this information without the reporting requirement?	Is the information reported publicly available? Any restrictions?	What are the Agency's QA/QC requirements?	Summary Comments: How good is this report for gaining an accurate accounting of fuel and carbon?
Minerals Management Service	MMS-4054A Oil and Gas Operations Report (OGOR) Part A - Well Production	Federal offshore and Federal/Indian onshore MMS lessees	All MMS lessees	MMS lease/agreement number; Production month; Operator information; Operator well number; Well status code; Days produced; Production volume (bbl for oil); Injection volume	Depends on the point of royalty determination	None	Monthly, 45 days following the reporting month	Operating information	Yes	Historical data available: http://www.gomr.mms.gov/homepg/pubinfo/freeasci/product/freeprod.html	Compliance asset management compares to royalty on the MMS-2014	Report does not contain information on carbon content of fuel
Minerals Management Service	MMS-4058 Production Allocation Schedule Report (PASR)	Operators of facility/measurement point handling production from Federal offshore	Required for Federal offshore only	Production number; API gravity; Operator information; Operator/area/block; Injector (oil/gas/both); Metering point; MMS lease/agreement number; Sales/transfers volume	Depends on the point of royalty determination	None	Monthly, 45 days following the reporting month	Operating information	Yes	No; Offshore Minerals Management (OMM) has complete access	Compliance asset management compares royalty information on OGOR and PASR	Report does not contain information on carbon content of fuel
Federal Highway Administration	FHWA-551M Monthly Motor-Fuel Consumption	State agencies that collect the motor-fuel tax for their respective states	All	State name, Year and month of sale or transfer, Volumes (gallons or liters)	N/A	N/A	Monthly	Tax record	Yes	Yes	None	Report does not contain information on carbon content of fuel
Army Corps of Engineers	ENG Form 3925 Vessel Operation Report, Statement of Freight and Passengers Carried	All domestic operators engaged in commercial activity on navigable waters	Not all -- 3925-B and 3925-P may be submitted in lieu of this form	Loading and discharge information; Cargo data: commodity, quantity, unit, weight per unit, net tons; Shipper information	N/A	Trips less than 1 mile not required to be reported	Monthly	Operating information	Yes	Aggregated data	Data submissions taken at face value in general; Some dock receipts to reconcile	Report does not contain information on carbon content of fuel
Army Corps of Engineers	ENG Form 3925B Vessel Operation Report, Statement of Freight and Passengers Carried (Shallow Draft Inland Traffic)	Shallow draft barge and tow boat operators	All	Vessel information; Origin and destination information; Cargo data: commodity, tons	N/A	Trips less than 1 mile not required to be reported	Monthly	Operating information	Yes	Aggregated data	Data submissions taken at face value in general; Some dock receipts to reconcile	Report does not contain information on carbon content of fuel


Petroleum Administration
for Defense Districts
PADD 4:
Rockies
PADD 5:
West Coast,
AK, HI
PADD 2:
Midwest
PADD 1:
East Coast
PADD 3: Gulf Coast

Oil & Gas Journal 200, 2006

Company	2006 Worldwide Liquids Production (Million Bbl)	2006 U.S. Liquids Production (Million Bbl)
BP		213.89
ExxonMobil Corp.	832.00	116.00
ConocoPhillips	534.00	162.00
Chevron Corp.	632.00	169.00
Anadarko Petroleum Corp.	86.00	54.00
Devon Energy Corp.	78.00	38.00
Occidental Petroleum Corp.	142.00	98.00
Marathon Oil Corp.	86.00	28.00
El Paso Corp.	7.69	7.44
Chesapeake Energy Corp.	6.76	6.76
Apache Corp.	86.25	27.31
Amerada Hess Corp.	94.00	17.00
Dominion Exploration & Production	24.95	9.75
XTO Energy Inc.	20.80	20.80
Noble Energy Inc.	27.34	16.72
EOG Resources, Inc.	13.65	10.68
Williams Cos. Inc.	NA	NA
Murphy Oil Corp.	27.70	7.70
Pioneer Natural Resources Co.	17.82	14.09
Pogo Producing Co.	13.48	8.11
Newfield Exploration Co.	9.00	7.80
Questar Corp.	2.60	2.60
Cimarex Energy Co.	0.27	0.27
Helix Energy Solutions Group Inc.	3.40	3.40
Petrohawk Energy Corp.	1.56	1.56
Forest Oil Corp.	8.03	6.89
Range Resources Corp.	4.25	4.25
W&T Offshore Inc.	6.46	6.46
Cheniere Energy Inc.	0.00	0.00
Whiting Petroleum Corp.	0.67	6.70
Plains Exploration & Production Co.	18.98	18.98
Southwestern Energy Co.	0.70	0.70
Denbury Resources Inc.	8.37	8.37
Stone Energy Corp.	5.59	5.59
Encore Acquisition Co.	7.34	7.34
St. Mary Land & Exploration Co.	6.06	6.06
Quicksilver Resources Inc.	1.33	1.33
Comstock Resources Inc.	2.30	2.30
Unit Corp.	1.45	1.45
Kinder Morgan CO2 Co. LP	15.63	15.63
Cabot Oil & Gas Corp.	1.42	1.42
Energen Resources Corp.	3.65	3.65
Equitable Supply	0.11	0.11
Houston Exploration Co.	0.94	0.94
Penn Virginia Corp.	0.38	0.38
Swift Energy Co.	7.90	7.18
ATP Oil & Gas Corp.	3.27	3.25
Ultra Petroleum	2.20	0.59
Rosetta Resources Inc.	0.58	0.58
Seneca Resources Corp.	3.61	3.34
Berry Petroleum Co.	7.18	7.18
Bill Barrett Corp.	0.70	0.70
Fidelity Exploration & Production Co.	2.10	2.10
CNX Gas Corp.		
Energy Partners Ltd.	3.01	3.01
Delta Petroleum Corp.	1.35	1.35
Petroleum Development Corp.	0.63	0.63
Clayton Williams Energy Inc.	2.37	2.37
Belden & Blake Corp.	0.37	0.37
Callon Petroleum Co.	1.63	1.63
DTE Gas & Oil Co.	NA	NA
Peoples Energy Production	0.35	0.35
Brigham Exploration Co.	0.44	0.44
PetroQuest Energy Inc.	0.70	0.70

Carrizo Oil & Gas	0.26	0.26
Goodrich Petroleum Corp.	0.47	0.47
Meridian Resource Corp.	0.86	0.86
Quest Resources Inc.	0.01	0.01
Parallel Petroleum Corp.	1.15	1.15
McMoran Exploration Co.	1.55	1.55
Black Hills Corp.	0.40	0.40
Atlas America Inc.	0.15	0.15
Warren Resources	0.46	0.46
Edge Petroleum Corp.	0.57	0.57
Toreador Resources Corp.	0.58	0.06
Prime Energy Corp.	0.38	0.38
Legacy Reserves LP	0.75	0.75
Aurora Oil & Gas Corp.	0.02	0.02
GMX Resources Inc.	0.07	0.07
Challenger Minerals, Inc.	0.54	0.10
Gulfport Energy Corp.	0.87	0.87
NGAS Resources Inc.	0.04	0.04
Arena Resources Inc.	0.90	0.90
Dorchester Mineral Ltd.	0.34	0.34
Gasco Energy Inc.	0.02	0.02
Cano Petroleum Inc.	0.19	0.19
Exploration Co.	0.79	0.79
Harken Energy Corp.	0.17	0.17
Abraxas Petroleum Corp.	0.20	0.20
Contango Oil & Gas Co.	0.04	0.04
Crimson Exploration Inc.	0.18	0.18
Panhandle Royalty Co.	0.10	0.10
American Oil & Gas Inc.	0.04	0.04
New Century Energy Corp.	0.12	0.12
Double Eagle Petroleum Co.	0.01	0.01
Hallador Petroleum Co.		
Infinity Inc.	0.08	0.08
Dune Energy Inc.	0.04	0.04
PRB Energy Inc.		
Evolution Petroleum Corp.	0.05	0.05
Galaxy Energy Corp.		
Credo Petroleum Corp.	0.04	0.04
Teton Energy Corp.		
FX Energy Inc.	0.09	0.09
Petrol Oil & Gas Inc.	0.02	0.02
Westside Energy Corp.	0.02	0.02
Royale Energy Inc.	0.02	0.02
New Frontier Energy Inc.		
Tri-Valley Corp.	0.01	0.01
Tengasco Inc.	0.19	0.19
San Juan Basin Royalty Trust	0.04	0.04
Adams Resources & Energy Inc.	0.08	0.08
Cross Timbers Royalty Trust	0.14	0.14
Houston American Energy Corp.	0.05	0.02
EnDevCo Inc.	0.03	0.03
Aspen Exploration Corp.		
Daleco Resources Corp.	0.01	0.01
VTEX Energy Inc.	0.00	0.00
Reserve Petroleum Co.	0.03	0.03
GeoResources Inc.	0.13	0.13
United Heritage Corp.	0.01	0.01
Cubic Energy Inc.	0.00	0.00
Spindletop Oil & Gas Co.	0.03	0.03
Blue Dolphin Energy Co.	0.00	0.00
Basic Earth Science Systems Inc.	0.10	0.10
Petro Resources Corp.	0.00	0.00
Fieldpoint Petroleum Corp.	0.05	0.05
John D. Oil and Gas Co.	0.00	0.00
Mexco Energy Corp.	0.02	0.02
Apache Offshore Investment Partnership	0.07	0.07
Oakridge Energy Inc.	0.02	0.02
Texas Vanguard Oil Co.	0.06	0.06
Pioneer Oil & Gas	0.01	0.01
Pyramid Oil Co.	0.07	0.07

Permian Basin Royalty Trust		0.75		0.75
Sabine Royalty Trust		0.46		0.46
Miller Petroleum Inc.		0.01		0.01
GSV Inc.		0.00		0.00
LL&E Royalty Trust		0.04		0.04
Bayou City Exploration Inc.		0.00		0.00
Ness Energy International Inc.		0.00		0.00
Lucas Energy Inc.		0.01		0.01
Capco Energy Inc.	NA		NA	
Empiric Energy Inc.	NA		NA	
Petrol Industries Inc.	NA		NA	
Shell Exploration and Production Company				

Companies listed in OGJ 2005 but not in 2006

Altex Industries Inc.
Blue Ridge Energy Inc.
Burlington Resources Inc.
Cadence Resources Corp.
EnCana
Hunt Oil Company
KCS Energy Inc.
Kerr-McGee Corp.
Kestrel Energy Inc.
Natural Gas Systems Inc.
Oneok Inc.
Remington Oil & Gas Corp.
Resource America, Inc.

Torch Energy Services
TotalFinaElf
Trek Resources Inc.
Unocal Corp.
Venoco
W & T Offshore, Inc.
Western Gas Resources
Westside Energy Corp.
Whittier Energy Corp.